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GEOTHERMAL & GEOPRESSURE BLOWOUT CONTROL

Phase I: Study of Existing Technology
Phase II: Program Plan for Geothermal & Geopressure
Blowout Control

By
William A. Rehm
W. C. Goins, Jr.

November 1978

Work Performed Under Contract No. EG-76-C-07-1603

Maurer Engineering, Inc.
Houston, Texas

MASTER

U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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PHASE I

STUDY OF EXISTING TECHNOLOGY

GEOPRESSURE BLOWOUT CONTROL

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PHASE II

PROGRAM PLAN FOR GEOTHERMAL BLOWOUT CONTROL

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**PHASE I
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Division of Geothermal Energy
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Mod No. A003**

**November 1978
MEI REPORT - TR78-27 (Book 1)**

FOREWORD

The following report is part of "A STUDY OF TECHNOLOGY IN WELL CONTROL FOR GEOTHERMAL AND GEOPRESSURED WELLS" prepared for The Department of Energy under Contract No. EG-76-C-07-1603, Modification No. A003.

There are four reports in the series:

1. Geothermal Well Control;
2. Geopressure Well Control;
3. A Program Plan for R&D in Geothermal Well Control;
4. A Program Plan for R&D in Geopressure Well Control.

The purpose of this study is fourfold:

1. Assess the present state of technology in well control relating to geothermal and geopressure wells;
2. Propose improved operating methods;
3. Propose improved equipment;
4. Develop a program plan of research and development necessary to assure safe and acceptable operating methods and equipment.

The project has been divided into separate sections for geopressure and geothermal drilling so that the problems may be addressed in a more logical manner. Therefore, there is some duplication of material in the report because the information is pertinent to both geothermal and geopressure well control.

The state-of-the-art in any type of operation is a moving definition. The cutoff date in this report series is information that was available in the first quarter of 1978.

GEOTHERMAL BLOWOUT CONTROL

SUMMARY

Present geothermal drilling practices are adequate since there have been no major blowouts of geothermal drilling wells. This condition is likely to exist until formations with higher temperatures and/or higher pressures are encountered.

At present the formation pressures in geothermal fields are generally sub-normal, or less than the pressure that would be exerted by a column of cold water from the reservoir to the surface. The temperatures encountered have been moderate and only in a few instances have the surface circulating temperatures of the drilling fluid exceeded boiling. Steam wells have higher surface temperatures, but compensated with much lower pressures.

The net result is that the pressures and temperatures that would have or could have caused serious blowouts have not been drilled and geothermal drilling has been spared a major blowout.

The condition of moderate temperatures and low pressures is already being changed and this will inevitably lead to a situation where blowouts could occur.

Fortunately, the drilling guidelines already exist that will provide a framework for reasonable assurance that wells will be kept under control. These guidelines are presented in USGS Geothermal Drilling Regulations, State of California Geothermal Drilling Regulations, and USGS Offshore Continental Shelf Drilling Regulations.

The problem of suitable equipment is not as clear as the drilling guidelines. Investigative and developmental work needs to be undertaken to assure that the well control equipment will function in the very hot environment of high-temperature geothermal wells and worst-case conditions. The final step in worst-case conditions is a remotely operated drilling rig that will allow the crew to handle very hot pipe and fluids from a safe distance.

The hazards of geothermal drilling are relatively moderate, and while it is possible to postulate major blowout from a worst-case analysis, the pressures, temperatures, and gasses have not yet been encountered that would make this a reasonable supposition. Continued geothermal drilling may lead into these hazardous areas and steps should be taken now to obtain the equipment and techniques needed to handle the extreme temperatures that may occur.

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GEOTHERMAL BLOWOUT CONTROL

I. CAUSES OF WELL BLOWOUTS

INTRODUCTION

A blowout, in the strictest sense, is uncontrolled flow from a wellbore. The blowout develops from a lack of balance in the fluid system used to carry the debris, or cuttings, from the wellbore. Ordinarily, the weight of the drilling mud system is greater than formation pressures, thus controlling the well. Excessive drilling mud weight must be avoided to prevent downhole problems and even loss of the drilling fluid to the subsurface formations.

As long as records have been kept, there have been some blowouts when drilling wells. Water wells have provided some spectacular artesian spouts. Accounts of oil well drilling in the early 1900s tell of dramatic blowouts at Spindletop, Signal Hill, and Oklahoma City. These are small beside the Cierro Azul in Mexico, the great blowout in Romania, and the early development in the Middle East fields by British Petroleum. Many blowouts that occurred in early oil fields were considered to be "gushers" -- a natural way of producing a well, or at least an unavoidable problem. Steam or geothermal blowouts have been less common, partly because there are fewer steam wells and partly because of limited well pressures in the typical well.

The cable-tool rig made it difficult, if not impossible, to control a high-pressure well. But with the advent of rotary drilling and a circulating mud system, it became practical to

control earth pressures. In the early 1900s, blowout preventers were developed that could close in a well but still allow circulation of the mud system (Figure 1-1).

Figure 1-1. 1903 Blowout Preventer.
(From Brantley - early B.O.P.)

The Baroid Division of National Lead Company was formed in 1932 to provide finely ground barite ore, the most efficient material that increases the density of drilling mud.

The API Technical Drilling Papers between 1930 and 1960 were full of discussions on how to avoid blowouts and how to use blowout control equipment.

The major breakthrough in well-control techniques came with the paper of O'Brien and Goins in the API reports in 1960. The background and need for well-control techniques were further clarified by the 1965 SPE paper of Hottman and Johnson on the detection and measurement of formation pressures from well logs. Since then, technology and associated equipment have developed rapidly and have been accepted throughout the petroleum drilling industry. The blowout is no longer accepted but is a rare and expensive event.

Water well drilling and mining exploration have adapted oil well drilling concepts where high pressures or some danger exist. But, for the most part, the technology and equipment for well control remains within the oil and gas well drilling industry.

As exploration and exploitation of geothermal resources grows, a close look needs to be taken at the technology transfer of well-control methods and equipment from oil and gas well drilling to geothermal drilling.

GEOHERMAL WELL-CONTROL PROBLEMS

Safe drilling in the geothermal environment requires that:

1. The water, steam, gas, or other formation fluids must be controlled in such a manner as to prevent casualties among the crew;
2. The drilling rig and equipment must be protected from unreasonable wear or destruction;
3. Environmental interests must be protected;

and further that:

4. The reservoir must be protected from damage or waste;
5. Fresh-water sources must be protected.

The practical result of these requirements is that the formation fluids must be dominated and controlled without exerting unnecessary pressure that would cause fracturing of the earth, formation damage, or equipment failure.

The existence of fractures or incipient fractures in the earth, which are common to most geothermal conditions, exerts a major constraint on any brute-force approach to controlling a well. The control procedures must not open the natural fracture system or overbalance the water or steam in the fracture system.

The temperatures of geothermal fluids will damage elastomers and plastics used as sealing elements in mechanical equipment. High temperatures may break down normal lubricating oils and

cause expansion and seizing of valves, chokes, and other moving elements (see Figure 1-2).

Figure 1-2. Geothermal production valves.

Special valves are also required for choke and kill manifolds. (Courtesy WKM)

Superheated waters are difficult to handle because of flashing and deposition of soluble material. Flashing is hazardous to personnel and tends to damage electrical, pneumatic, and hydraulic equipment on or around the mud pits.

Within all these limits some of the basic well-control techniques will work provided that applicable techniques are identified for the various types of reservoirs encountered and provided equipment is capable of handling the temperatures and salt deposition (see Figure 1-3).

Figure 1-3. Silica deposition on a wellhead at the Salton Sea Geothermal Test Site. (Lawrence Livermore Geothermal Test Site)

Potential Causes of Geothermal Well Kicks or Blowouts - by Types

Wellbore conditions that will cause a surface or underground blowout can occur in several ways. The Geothermal Division of the California Division of Oil and Gas has identified five types of blowouts that have occurred in geothermal wells. Only three of these have occurred in drilling (see Anderson, David N.). These are discussed in conjunction with Figures 1-4, 1-5, 1-6.

Other situations that could lead to potential well kicks and blowouts are discussed starting with steam unloading shown in Figure 1-7 and continuing through Figure 1-10.

NOTE

This has occurred
at The Geysers and
in New Zealand.

Figure 1-4

Punky Earth (California...Anderson, David N.)

A punky earth blowout (Figure 1-4) can occur in hydrothermally altered rock (incompetent, sheared, crumbly, and fractured) where a shallow producing zone with pressure in excess of hydrostatic pressure is present and inadequate conductor and/or surface casing is set.

A blowout occurs when steam or hot water under pressure is allowed access to the punky earth below the shoe of the casing or surface pipe, and the pressure is great enough to break through the altered rock to the surface.

NOTE

This has occurred
at The Geysers.

Figure 1-5.

Landslide (California...Anderson, David N.)

The causes of a landslide blowout (Figure 1-5) are readily apparent and can be best categorized as:

- a. Failure to recognize unstable surface conditions prior to and during the construction of the drilling location.
- b. Failure to construct the drill site in accordance with acceptable soils engineering standards.

NOTE

This has occurred
in Surprise Valley,
California.

Figure 1-6

Inadequate Casing (California...Anderson, David N.)

Blowouts due to inadequate casing (Figure 1-6) occur when little or no surface casing is set and abnormally high pressures are encountered in shallow reservoirs. The prime example of this type occurred when a well with less than ten feet of casing and drilled to a depth of about 100 feet in a hot springs complex blew out.

STEAM UNLOADING

Figure 1-7.

Steam Unloading

In several instances, overheating of the drilling fluid has caused steam unloading of a well. This has happened with drilling muds circulated up after a trip, and it is quite common in drilling in the Imperial Valley. The steam unloading kicks were not violent enough to cause the hole to unload deep enough to blow out; they were expected and handled as part of the drilling process.

Other instances of steam unloading have occurred when using water blankets during cementing and water packers in the annulus of a well. These events caused some inconvenience and lost time, but they were short-term kicks rather than true blowouts.

Steam unloading should become more serious as geothermal wells drill into hotter formations. The primary danger of steam unloading is to the rig crew, but if enough fluid flashes to steam, it could cause a pressure reduction in the mud column that would allow the well to blow out.

ARTESIAN FLOW

Figure 1-8.

Artesian Flow

In areas of high relief or dipping beds, artesian drive due to either the relief or to the lighter hot-water balance against a cooler water may cause abnormally high well pressure and lead to a blowout. With a short string of casing, it might be difficult to control pressures without careful planning.

Both theory and experience in oil and gas drilling indicate that there are certain conditions where a diverter system has to be used, rather than trying to close a well in because of the danger of lost circulation. The artesian flow may, in some cases, be similar to Inadequate Casing (California), but it is not always possible to provide adequate casing in the shallow hole or in fractured formations.

LOST CIRCULATION BLOWOUT

Figure 1-9.

Lost Circulation

A significant cause of well blowouts in the Rocky Mountain provinces and in the Middle East has been lost circulation. While this has been associated with oil and gas drilling, there is no reason to believe that it could not occur in geothermal drilling. Either of two conditions could cause a blowout. A fractured or

faulted zone in the bottom of the hole could open and accept drilling mud. The mud level in the hole would drop low enough to allow upper formations to flow into the hole. It also might be that in a geothermal well an upper formation will take mud or re-open when mud weight has to be increased to control bottom-hole pressure. It may also be that thick, dense mud or cement will fracture a formation that previously resisted the gradient imposed by less-dense mud. The mud column will drop reducing bottom-hole pressure and the well will then blow out (Figure 1-9).

Figure I-10.

Not Filling the Hole

One of the most common causes of blowouts in oil and gas drilling has been failure to fill the hole during a trip. The height of the mud column drops as the pipe is pulled, which reduces pressure on the bottom of the hole. This allows the formation fluids to flow, setting up a well kick and the beginning of a blowout.

Other Types

There are a number of other possibilities for geothermal blowouts while drilling: pressure from upthrust formations, improper handling of pumps, gas in the wellbore, and a poor understanding of how to handle chokes and blooie lines.

Assessment of Causes

Of the many well-drilling situations that could cause blowouts, only two have actually been related to the drilling process itself. These are blowouts due to short casing strings and blowouts due to geothermally altered surface formations. Both situations are essentially the same.

Steam unloading of a well has occurred rather frequently, but it has never developed into a blowout. So far, unloading has been relatively mild and has ended spontaneously.

Geothermal well problems relating to terrain (landslides), steam kicks due to alteration of the rock, and production blowouts resulting from casing parting are real problems with geothermal wells, but they are problems that have solutions.

Blowouts in geothermal drilling wells have not yet been a major problem and there is no reason to believe that this situation will change until higher pressure and higher volume wells are discovered.

There are two other categories for potential blowouts in geothermal drilling. These are blowouts due to a failure in procedures and blowouts due to equipment failure. These two categories are covered in Section II, Well-Control Procedures and Section III, Well-Control Equipment.

Potential Causes of Kicks or Blowouts - by Reservoir Category

Hot, Dry Reservoirs

There appears to be little danger of a blowout in hot, dry reservoirs.

The hot rocks may generate flowing steam if water is inadvertently injected. This type of blowout, however, would be of limited duration. It appears that the worst problem would be inadequately cased surface water that would run into the hole, causing an intermittent geyser. This would probably be the result of casing failure.

Vapor-Dominated Reservoirs

The pressure within a natural steam reservoir should always be less than the hydrostatic pressure exerted by a column of water extending to the surface of the ground. Therefore, steam wells will normally be drilled with air or water.

Drilling with air is on a "controlled blowout basis;" i.e., a steam kick would be expected and would be controlled with surface equipment. A steam blowout would then be due to a procedural failure or to surface equipment failure, including damage caused by the presence of hydrogen sulfide in the blowing steam.

When drilling with water, steam blowouts could result from superheating of the water and its flashing to steam. In this case, the surface equipment might be too hot to operate. If this happened or hydrogen sulfide was present, equipment failure could result in a long period of uncontrolled blowing.

When drilling with water or light mud, lost circulation could cause a blowout. This seems rather unlikely in a vapor reservoir, since the available information indicates that killing or plugging of the well is more likely.

The most probable cause of a steam blowout is shallow steam. If steam is tapped in the first several hundred feet of hole, the blowout preventers will not be secured because there will be no structurally sound surface casing seat. The steam could be temporarily uncontrollable, so a diverter system must be used. If the well was shut in, the steam could fracture the formation (due to the short surface pipe or altered formations) and surface around the rig.

The problems of "punky" surface formation due to geothermal alteration or landslides as reported in The State of California documents is a problem that must be faced on a civil engineering basis during the design of the well; it should not be considered as a well-control problem. It is difficult to see what rig site contingency plan or training could be of benefit when operating on punky ground.

Liquid-Dominated Reservoirs

Water reservoirs can develop significant pressures, and blowouts could occur as a result of fluid drive and/or flashing of the drilling mud.

An early problem may arise if shallow water under pressure is encountered before casing is cemented into the ground. Artesian flows of this nature have occasionally been almost impossible to halt.

In deeper drilling, blowouts may occur because of fracturing of rock above the water zone with subsequent loss of mud from the hole into the fracture. This would reduce the pressure head of the mud above the water zone and allow it to flow.

Drilling mud that is too light will allow the reservoir to flow. The Phillips Petroleum work in Roosevelt Hot Springs indicates that subsurface pressures in geothermal areas can be significantly above normal and require heavy drilling mud.

Failure to fill the hole during a trip is a common cause of well kicks and blowouts in oil and gas drilling and could be a problem in geothermal liquid-dominated reservoirs.

If a mud were to flash to steam in the upper part of a hole, the hole could unload enough to reduce the mud column pressure and allow the well to flow.

II. WELL-CONTROL PROCEDURES

To provide for successful handling of kicks when drilling geothermal wells, there must be adequate well design. Well-control techniques are highly developed, but successful handling of kicks depends on good cement bonding and sufficient mechanical strength of the tubular goods and exposed formations to withstand the wellbore pressures. Failure to design the cementing and casing adequately can result in loss of circulation, underground blowouts, or broaching of the formation fluid through the upper formations to the surface.

As a generality, formation strength tends to increase with depth. Casing must have sufficient mechanical strength and be set deep enough for the formation to withstand the pressure gradients of the drilling fluid plus the temporary increase in wellbore pressure while handling the kick. However, high pressure differentials developed on low pressure formations can result in differential sticking of the drill string so pressure needs to be handled carefully.

TECHNOLOGY TRANSFER FROM OIL AND GAS DRILLING

The existing state of technology in well-control is excellent and capable of handling well kicks. The land drilling crews have not, however, been very extensively trained in this technique. There is almost no special technology developed for workover or completion crews and they are unprepared to undertake any well-control beyond pumping down the well to force well fluids back in the formation and circulation of drilling fluids for cleanup.

Figure 11-1

WELL CONTROL PRACTICES
EXXON COMPANY, U.S.A.

IF PIT VOLUME GAIN OR WELL FLOW OCCURS, DRILLER
SHOULD IMMEDIATELY:

1. PULL KELLY ABOVE ROTARY.
2. SHUT PUMPS DOWN.
3. OPEN HCR VALVE. CHOKES TO BE OPEN WHILE DRILLING.
4. CLOSE HYDRIL.
5. CLOSE CHOKES (NOTE—LIMIT ON CHOKE PRESSURE MAY BE SPECIFIED BY EXXON DRILLING SUPERINTENDENT).
6. RECIPROCATE PIPE SLOWLY.
7. RECORD DRILL PIPE AND CASING PRESSURES AND VOLUME OF PIT GAIN. NOTIFY TOOLPUSHER AND EXXON DRILLING SUPERINTENDENT.
8. IF SO INSTRUCTED BY EXXON DRILLING SUPERINTENDENT, RESUME CIRCULATION AT REDUCED RATE. HOLD PUMP RATE CONSTANT.
9. INITIATE CIRCULATION (AT REDUCED RATE) WITH CASING BACK-PRESSURE SET EQUAL TO OR SLIGHTLY HIGHER THAN THE SHUT-IN CASING PRESSURE. (NOTE—EXXON DRILLING SUPERINTENDENT WILL SPECIFY EXACT PRESSURE). WHEN PUMP REACHES DESIRED SPEED AND PUMPING PRESSURE IS ESTABLISHED, THE CASING PRESSURE SHOULD BE ADJUSTED TO MAINTAIN THE ESTABLISHED DRILL PIPE PRESSURE.
10. NOTE DRILL PIPE PRESSURE AND CONTINUE TO ADJUST CHOKE TO HOLD THIS PRESSURE CONSTANT UNTIL KICK HAS BEEN CIRCULATED FROM WELL.

NOTE—PUMP RATE MUST BE HELD CONSTANT DURING CIRCULATION.

HDQ 8/74

Constant Bottom-Hole Pressure

Well control procedures are based upon pumping or circulating a well under pressure by means of a choke on the annulus. Well control is accomplished by utilizing the choke to force the pump pressure to remain high enough to pressurize the hole. The pressurization of the hole is equivalent to or higher than the pressure required to dominate the reservoir.

Mud weight is substituted for surface imposed pressure. The increased mud weight or density is calculated according to the basic equations:

$$P = D \times Wt \times f \quad (\text{Eq. TII-1})$$

where

- P = Pressure of Mud Column
- D = Depth
- Wt = Mud Density
- f = Units Constant

from which

$$(\Delta) Wt = \frac{P_2}{D \times f} \quad (\text{Eq. TII-2})$$

where

- $(\Delta) Wt$ = The increase in mud density to be distributed through the hole.
- P_2 = The shut in surface pressure on the drill pipe which is full of mud.

So in simplest form, a well is killed by these steps:

- 1) Shut in the BOP when an increase in flow or pit level is seen.
- 2) Read and record the shut in pressures on the pump gauge (the drill pipe gauge) and casing gauge.
- 3) Use Eq T11-2 to figure an increased mud weight - and mix that in the pits.
- 4) Then open the choke and start pumping at a slow rate - the kill rate - where the pump pressure is already known. This pressure/rate relationship is measured by the crew each tour.
- 5) Adjust the choke to keep the casing pressure the same as when shut in.
- 6) At this time, the pumping pressure should be equal to the known pump pressure at the slow rate plus the shut in drill pipe pressure.
- 7) As the heavier mud is pumped down the drill pipe, the drill pipe pressure is reduced evenly until when the new mud reaches the bit, the final circulating pressure is on the pump (drill pipe) gauge.
- 8) The final circulating pressure is:
$$\text{F.C.P.} = \text{The kill rate pressure} \times \frac{\text{new mud wt}}{\text{old mud wt}}$$
- 9) Continue to pump at the kill rate and hold the final circulating pressure on the drill pipe pressure gauge with the choke until the well is dead.

There are a number of details in the preceding steps that are often varied, but these mostly relate to how to obtain the initial circulating pressure and when to increase the mud weight. They do not change the method nor are the results significantly different.

This technique, "the constant drill pipe pressure" or "constant bottom-hole pressure" method, is the best way to circulate an intrusion out of the hole and increase the mud density so as to replace surface pressure with mud pressure.

Since hot salt water can be expected to upset the drilling mud, the killing technique should involve a comparison of the calculated initial circulating pressure and the rig developed initial circulating pressure with the lower valve to be used after a 10 minute period (Steps 4 and 5 in the preceding discussion). The constant casing pressure start up should be carefully practiced so as to allow for "breaking" circulation after a down period.

Hole Fill-up

One of the major procedural failures leading to well kicks and blowouts in oil and gas drilling is failure to fill the hole during a trip, or to keep the hole filled while logging or running casing. Any time that the drilling fluid is dominating the reservoir pressure, reduction in the drilling fluid head will cause the reservoir to flow. For the well to kick, however, the reservoir pressure has to be great enough to make the fluid flow out of the hole.

As greater pressures are found in geothermal reservoirs or as conditions occur that will cause increased formation gradients, the practice of filling the hole and measuring the fillup will become more important in geothermal drilling.

WELL-CONTROL PROCEDURES BY RESERVOIR CATAGORY

Hot Dry Reservoirs

When air drilling, a blowout or well kick on a hot dry reservoir would normally be a steam unloading of water that has been injected into the well or has entered the wellbore from a shallow fracture or failure of cement or casing.

*If the resulting steam does not contain dangerous gases, a diverter system to protect the crew on the rig floor and to put the steam at some reasonable distance should be all the well-control procedure required. Steam from dry rocks should be short lived or of a small volume.

*In case of dangerous gases, the emergency measure would be to pump the wellbore full of cold water to cool the reservoir and to repress the emission of the gases.

*Control of H_2S gas when air drilling would require the use of the system described under "Equipment".

*Combustible gasses could cause downhole fires or blooie line explosions and if present in more than trace amounts should call for a site specific analysis.

*When drilling hot dry reservoirs with water or drilling mud, the potential for steam unloading always exists. When this occurs, the well must be circulated through a mud/heat exchanger. The well might have to be shut in and circulated under choke control if the unloading was violent enough. Additives to the mud system or an alkaline mud system would be adequate to control acid gases that might be present in a well kick.

Vapor-Dominated Reservoir

Steam wells that are drilled by air, such as at The Geysers, are drilled in a controlled blowout basis. There is then no valid blowout term since that is the normal condition and the equipment is available for control. (This is described under Equipment.)

*Vapor dominated reservoirs are generally subnormally pressured and any blowout could be controlled by pumping cold water into the hole. Since shocking the hole and casing tends to damage the reservoir and cause casing parting, the water treatment should be the last choice and every attempt should be made to divert the steam until the well could be capped or put into a production line.

*The most likely type of problem would be a blowout from parted casing in the upper part of the hole or from shallow steam in hydrothermally altered formations. In both of these cases, the well could be killed with water if the water could be pumped past the fractured zone. If it was impossible to re-enter the old hole, then a directional hole would have to be drilled to kill the old well.

*When water or mud is used to drill the steam reservoir, a well kick or blowout could be controlled by circulating the system under choke control until the well was cooled or the mud weight increased. Because of the low pressure in steam wells, it seems a mud weight increase would be an unlikely condition.

Liquid-Dominated Reservoirs

The liquid dominated reservoirs on which drilling information is available indicates that relatively high pressured waters at temperatures approaching 700°F will be encountered.

Two conditions then exist that may cause blowouts. First, the reservoir drive will be sufficient to unload muds from the hole; and secondly, steam flashing may occur to initiate the unloading.

The most common approach to controlling these wells is to choke them down to some fixed pressure at the annulus and then to pump cool weighted mud until the well is killed. This is crudely effective, but can cause lost circulation into the fractured zones which are also some of the primary production zones. The Constant Bottom-hole Pressure Technique should be used for controlling well kicks and steam flashing. (See Task II, Technology Transfer) This method, which is quite simple and universally used in oil and gas drilling, will solve the problem of reservoir drive and steam flashing. It differentiates between simple circulation needed for steam flashing and mud density increases needed to control reservoir drive; and circulation can be initiated without forcing mud into the reservoir formation.

The main modifications needed in the technology transfer of this technique are to use methods to minimize lost circulation, to compensate mud density terms for temperature, and to make clear set rules on cooling circulation to dampen steam flashing.

III. WELL-CONTROL EQUIPMENT

INTRODUCTION

This section discusses the applicability and limitations of available well-control equipment with regard to the special problems of geothermal drilling.

A somewhat broad viewpoint of what constitutes well-control equipment is used in this report. It is difficult to delineate the exact limits of what is and what is not well-control equipment. If any error is made, it is on the safe side.

EQUIPMENT SUMMARY

Blowout Preventer Stack

The blowout preventer (BOP) stack on geothermal wells has worked adequately in the past because temperatures were not above about 350°F for extended periods and the pressures were low. Work in the Roosevelt Hot Springs area of Utah indicates that temperatures up to 700°F and pressures up to several thousand psi will be encountered. This set of circumstances will require a new look at the surface stack.

Within the temperature and pressure limits required, high-temperature steels probably will not be a critical element. Adequate clearances for metal expansion appear to be available in most ram sets, but little information seems to be available on clearance dimensions with temperatures from 350° to 700°F.

The sealing elements in the ram bodies are related to the hydraulic operating mechanism and generally utilize O-ring seals and some lip seals. The use of a high-temperature material such as Viton may resolve any problem of temperature degrading the seals. The choice of a proper hydraulic fluid for the closing unit (so the hydraulic fluid and the seal rings match) would be an important part of operational efficiency. It might also be worthwhile to investigate the possibility of circulating the hydraulic fluid to keep temperatures lower.

The outstanding problem with BOP stacks is the packer elements used with the rams, the annular preventer, and the

rotating head. The packer element on the pipe rams is designed to be a self-feeding element that will seal even after considerable use and abuse. The use of high-temperature elastomers and or graphite-impregnated materials limits the self-feeding capability, at least in present designs, and probably will require more careful and frequent testing of the rams and shorter replacement periods.

The packer element on the rotating blowout preventer now in use at The Geysers is a high-temperature elastomer. With temperatures approaching 300° to 400°F, normal packer elements vulcanize to the drill pipe. The high-temperature compounds are more effective, although they are brittle and have a rather short life. With air-drilling temperatures much above those at The Geysers, the rotating blowout preventer packer may require continual water cooling.

The lip seals and sealing element of the rotating element, which uses a large bearing package, can probably be cooled by modifying the lubricating system for circulation.

The annular preventer is used in place of the rotating head, or along with the rotating head, when the pipe must be stripped out of the hole with the hole sealed. There is a great deal of difficulty in using the annular preventer in a geothermal well because the massive packer element is very temperature limited. The packer of the annular preventer distorts more than the packers of the ram or rotating preventer and is much larger. At present, the annular preventer can be used in the cooler, upper part of the hole, but it is not effective for sealing the hole and stripping pipe at the higher temperatures of geothermal wells unless kept cool by a water or mud circulating system.

The manifold and well-control choke are very much of an afterthought in geothermal drilling. Since most geothermal wells have low pressures, there is little need for choke and kill manifolds. The choke manifold may become useful in fluid-dominated reservoirs as the reservoir pressures become great enough to cause a significant flow at the surface. In these cases, the manifold will become a test tool as well as a blowout control tool.

The choke manifolds examined at several geothermal drilling sites were poorly designed for any well control or testing operation. There is no need for a conventional choke manifold for drilling in either hot rock or vapor reservoirs unless it would be possible to circulate water or drilling mud through the hole. The choke manifolds for liquid phase reservoirs need to have a large-diameter manifold pipe for testing large volumes of water, and high-temperature valves are needed to allow the fluid to be shunted in the manifold.

The common, adjustable choke of the needle valve type is not suitable for use in geothermal manifolds. Because of the design of the conventional choke, it has a tendency to gall and lock tight when heated. Until adequate modifications are made and proven, it would be better to use a fixed choke or an adjustable mud choke in the manifold.

Manifold valves are available for high-temperature work, and care should be taken to see that the valving in the manifold is suitable for high-temperature use. There are some limits on the type of valves that will seal throughout the temperature range. In the case of rising type valves, the stem packing is a critical element.

Float valves in use at The Geysers and in Cerro Prieto, Mexico, are adequate for present temperature and pressure conditions.

Auxiliary Surface Equipment

It is in the field of auxiliary surface equipment particularly needed in liquid reservoir drilling that severe limits to blowout control equipment appear.

Detection equipment (flow sensors or pit volume measurements) and the associated mud displacement equipment for trips are not generally rugged enough for geothermal mud temperatures. This usually leaves the detection of a kick or steam unloading to the obvious and late signs of overflowing pits or bell nipple.

The downstream choke gauges and manifold gauges do not generally use high-temperature diaphragms.

The mud system heat exchangers are simple mud/air exchangers and have no flash vessels for primary cooling ahead of them, nor are they capable of cooling under pressure.

The equipment in use has been adequate for the initial phases of exploration, but as drilling increases and wells become hotter, this equipment will become less satisfactory.

EQUIPMENT DESCRIPTIONS

Blowout Preventer Stack

The blowout preventer (BOP) stack used in geothermal drilling is a much smaller and lighter piece of equipment than the high-pressure systems used for geopressure drilling (compare Figures III-1 and III-2). The same restrictions apply to it, however; the bore of the stack must be large enough to pass the drilling tools, the stack must be pressure proof against the contemplated worst-case pressures, and it must be strong enough to resist bending moments and impacting forces.

Two other restrictions apply to the geothermal BOP stack. First, it must be operational in the temperature environment of geothermal drilling. All stacks are assembled with metallic seal rings so that sealing under high temperature is not dependent on an elastomer or Viton O-ring. The BOP stack is arranged so that elements that are temperature sensitive--seals and hydraulic lines--are away from the wellbore. Exceptions to this are the sealing elements of the rams, annular preventer, and drilling head. They are discussed in detail in following pages.

The second restriction to the geothermal stack is its geometry--size and height. The geothermal drilling rig is often small and even a truck-mounted unit. It is difficult to get the elements of the BOP stack under the rig floor. This is especially evident with the MSP 500 diverter system used in the Cove Fort area. The stacks used with air

drilling in The Geysers are so tall that problems arise in making the substructure high enough to clear the rotating head.

Anything that makes it more difficult to place the BOP stack under the rig requires a trade-off of drilling safety against some other mechanical or rig-related problem. The trade-off needs to be closely watched. The more-difficult or awkward-to-handle equipment may be causing more hazardous conditions than it solves. In other words, more BOP stack may not be better or safer. Examples of geothermal drilling BOP stacks are given in Figures III-3 through III-5. The banjo box, a special part of an air-drilled well BOP stack, is shown in detail in Figure III-6. This device routes returned air to the bleed line.

Figure III-1. BOP stack used at Cerro Prieto, Mexico

Stack Used on Surface Hole

- 1. Flow line.**
- 2. Annular preventer.**
- 3. Kill or choke line.**
- 4. Wellhead shut-off valve.**

Figure III-2. Blowout preventer stack for high-pressure well.

1. Annular preventer.
2. Double ram set.
3. Spool with side outlets and valves for choke and kill lines.
4. Single ram.
5. Wellhead flange clamp.
6. Hydraulic closing lines.
7. Manual ram locks.

Courtesy Cameron Iron Works

Figure III-3. California BOP stack.

From Campbell

Figure III-4. California BOP stack.

From Campbell

Figure III-5. BOP stack used in air drilling at The Geysers.

From Bannerman, Davis, and Wolke

Figure III-6. The banjo box is a spool and outlet for the blooie line when air drilling. When used at The Geysers, the banjo box can be shop made or it can be the body of a Cameron QRC pipe ram as shown above.

Courtesy Cameron Iron Works

Figure III-7. BOP stack plus muffler/dust cyclone used in air drilling.

From Turner and Rex

Several practical problems in air drilling are resolved with a muffler/dust cyclone like that used at The Geysers (Figure III-7).

Air-drilled cuttings return to the surface as dust. The dust is settled by injecting water into the blooie line ahead of the cyclone.

The large cyclone cylinder and the expansion chambers muffle the roar of produced steam when drilling near the bottom of the well. The air volume used in drilling is not enough to cause objectional noise, but the large volumes of steam produced from the well are noisy if released from a straight pipe.

H_2S is present in small amounts in the steam. Over a period of time, the odor occasionally has built up to objectionable levels. The peroxide and caustic soda additions to the blooie line reduce the H_2S .

Rotating Head

A rotating head (see example in Figures III-8 and III-9) is generally used in air drilling to divert the dust and air away from the rig floor to the bloop line. Additional uses for it include foam drilling or drilling with aerated mud. In geothermal drilling, a rotating head has obvious uses with air and steam drilling, but it may also be used when drilling superheated water reservoirs or when drilling muds are above the boiling point. In the latter case, the head becomes more of a rotating blowout preventer than a simple diverter.

The rotating head utilizes a stripper packer mounted on a ring that rotates on a bearing assembly. The rotating assembly is driven by a special square drive attached to the kelly. The rotation of the packer rubber while drilling limits the wear on the packer rubber to that induced by the up-and-down movement of the drill pipe. Once the kelly driver is removed, the drill pipe can be stripped in and out of the hole through the packer.

In normal air drilling, the packer does not have to be a pressure seal, because the bloop line is open to the atmosphere. The newest drilling heads developed for air drilling are reported to withstand pressures up to 2,000 psi and thus become a form of rotating blowout preventer if the bloop line is closed. These heads are for normal temperatures and have to be cooled for geothermal work.

As in all geothermal work, the basic limit of the equipment is in the elastomer packer and seals. Geothermal drilling needs a high-temperature rotating blowout preventer that can let the drill pipe and collars be stripped in or out of the hole and provide a seal against any H₂S gases, thus providing the function of both a rotating preventer and an annular preventer.

Figure 111-8. GRANT ROTATING DRILLING HEAD.

Please Note: The Grant Rotating Drilling Head is a diverter and NOT a rotating blowout preventer.

COMPONENT PARTS

The Rotating Head is generally the connecting link between the BOP stack and the rotary table. It is made up of four functional components, three of which rotate.

1. The body, which is essentially a drilling spool with a side outlet, is mounted to the stack and is stationary.
2. The Drive Ring assembly, which is integral to the body

and is never removed during operation. This assembly contains the bearings, seals and lubrication ports.

3. The Drive Bushing assembly, which mates with the Drive Ring and is removable. It includes a split Kelly Bushing, a Drive Bushing, and an attached Stripper Rubber.
4. Mud Slinger and Swing Bolt Clamp.

HOW IT WORKS

The split Kelly Bushing is made-up with a loose fit around the kelly. When the kelly is run in, this bushing automatically indexes itself inside the Drive Bushing. The rotary action of the kelly turns the bushing. The bushing turns the Drive Bushing, and consequently, the attached Stripper Rubber.

When the kelly is picked up, the shoulder on the lower kelly upset lifts the bushing with it. This automatically disengages the bushing from the Drive Bushing, and the bushing remains with the kelly in the rat hole.

Courtesy Grant Tool Company

Figure III-9. SHAFFER ROTATING BLOWOUT PREVENTER,
TYPE 50.

- Drill with well bore pressures up to 500 psi, which makes it useful for drilling in areas susceptible to kicks or blowouts, drilling under pressure, drilling with reverse circulation and circulating with air or gas.
- Strip pipe in or out of the hole at well pressures up to 1,000 psi with a stationary pipe stripper, which has a stripper rubber that changes shape to conform to the O.D. of drill pipe, tool joints and drill collars.
- Function as a bell nipple by latching a bell nipple extension into the body in place of the rotating assembly.
- Completely seal the top of the well bore by latching a blind sealing plate into the body in place of the rotating assembly.

The body **1** of the Type 50 is installed on top of the BOP stack with the flanged side outlets connected to the mud return line. Two threaded holes allow connection of fillup lines.

The kelly **2** rotates the kelly drive assembly **3**, which turns the rotating sleeve **4**. Stripper rubber **5** is attached to bottom of sleeve and turns with it, so the kelly moves up and down in the rubber but does not rotate in it.

Long-life, triple bearing assembly **6** splits compound loads into pure radial and pure thrust loads, each carried on separate roller bearings. The radial bearings are spaced to provide maximum support and resistance to off-center loads.

Quick-release bonnet **7** allows fast removal of rotating assembly **8** from body **1** to change stripper rubber **5** or drill bit. Just one-sixth of a turn unlocks the rotating assembly.

Reliable lip-type seals **9** seal around the rotating sleeve. Brass spacers between the seals centralize the unit and ensure uniform distribution of pressure to reduce wear on the packing assembly and the rotating sleeve.

Stripper rubbers **5** are made in various sizes to seal on kellys, drill pipe, drill collars, tubing and casing. The rubber is molded to movable steel latches attached to a steel ring, which move out to allow tool joints and pipe couplings to pass through.

Courtesy N. L. Shaffer

Annular Preventer

The purpose of the annular preventer is to close the annulus when anything other than drill pipe is in the BOP. Generally, when a well kick threatens, the annular preventer is closed first so the driller does not have to worry about the position of the tool joints and so the pipe can be moved to avoid sticking. The annular preventer is also used to strip pipe in or out of the hole. One type of annular preventer is shown in Figure III-10; pipe stripping through an annular preventer is shown in Figure III-11.

The annular preventer can be closed on the kelly, tool joints, drill collars, casing, or wire line. It can also close over the open hole, but this is not recommended because of the distortion of the packer.

The annular preventer is closed by hydraulic pressure on the closing piston. The "rubber" packer element is squeezed closed around the pipe. Annular preventers are usually closed with about 800 psi pressure. The time that it takes to close depends upon how long it takes to flow enough hydraulic fluid through the lines to operate the piston. The volume required to close varies from 10 to 100 gallons, depending on the annular preventer type and size and the control system. Annular preventers are "well energized," i.e., well pressure helps keep them closed.

The packer element of the annular preventer is thicker than the rotating head packer, and so correspondingly suffers more from high-temperature hardening. On geothermal wells, the annular preventer is limited by the temperature limits on the packer element.

**Figure III-10. HYDRIL ANNULAR PREVENTER,
TYPE GK.**

Cutaway view of GK BOP with packing unit fully open. The Hydril GK opens to full bore to allow passage of large-diameter tools through open bore as well as maximum annulus flow of drilling fluids. Packing unit returns to full open position due to normal resiliency of rubber packing unit. Retention of opening chamber pressure will ensure positive control of piston and reduce wear caused by vibration.

Cutaway view of GK BOP with packing unit closed on drill pipe. The packing unit seals off on tool joint, any size pipe, casing, or wireline to rated pressure.

Cutaway view of GK BOP with packing unit closed on square kelly. The packing unit seals off on square or hexagonal kellys to rated pressure.

Cutaway view of GK BOP with packing unit closed on open hole. Complete closure of packing unit safely holds well pressure, without leakage, equal to the rated working pressure of the preventer.

Courtesy Hydril

Figure III-11. SHAFFER SPHERICAL ANNULAR PREVENTER.

During stripping in, well pressure and pipe movement oppose each other. Well pressure compresses the rubber portion of the element against the steel segments as the tool joint moves down into the Spherical.

During stripping out, well pressure and pipe movement are in the same direction. Rubber is compressed firmly against the steel segments at the top of the element, but rubber at the bottom is only slightly compressed. This creates a "funnel effect" that makes it easy for a tool joint to pass through the sealing element.

At complete shutoff, the steel segments provide ample support for the top portion of the rubber. This prevents the rubber from flowing or extruding when confining high well pressure.

Courtesy N. L. Shaffer

Diverter System

There are many ways of diverting steam or gas from a shallow kick. The type of system shown in Figure III-12 is common. A similar system using a BOP on the bottom is used in the Cove Fort drilling in Utah. The system is used to divert any H_2S gas encountered. (There are sulphur mines in the vicinity.)

Annular Preventer
used as a diverter
(Hydril MSP 500)

Figure III-12. Diverter.

Courtesy Hydril

The annular preventer can be used as a diverter for shallow steam or gas because of the lower temperatures. It allows a larger full-bore opening than does a rotating head.

Ram-Type Blowout Preventers

The purpose of the ram-type blowout preventer is to seal off the annulus of the well or the open hole (see Figures III-13 and III-14). Ram-type preventers will seal against only the one size of pipe or open hole for which they are designed. The ram block is steel with only a small packer to seal at the face of the mating blocks and around the pipe. This provides a very strong, reliable, safe "valve" for closing off the wellbore.

A typical set of ram preventers (Figure III-14) consists of a "blind" ram to close on the open hole and a pipe ram sized to fit the drill pipe in use. As well pressures become higher and rigs larger, more rams are added to the stack. A pipe ram and a blind ram, or two pipe rams and a blind ram, are not unusual stack arrangements for geothermal drilling. This allows one of the rams to be changed to fit the casing size when casing is run.

In general, when pipe rams are used the pipe is not rotated or reciprocated. While rams were not designed for pipe movement, the pipe can be moved through the rams quite extensively without damaging the packer elements. A stripping technique utilizing pipe rams is quite common. When used in stripping, the closing pressure of 1,500 psi on the rams is usually reduced to about 800 psi.

Pipe rams should be operated hydraulically rather than manually. Manual operation is slow and can become hazardous to both the man (who is under the floor) closing the rams and the crew on the floor waiting for ram closure. Pipe rams are "well energized" so pressure in the well helps keep them closed. They can be locked closed either manually or hydraulically.

Pipe rams are well suited for their task in geothermal drilling. The sealing rings can be made of Viton material, which resists temperature. The ram sealing area is small and the distortion of the packer area is minimal, so problems with the sealing packer element are significantly less than with the annular preventer.

Some care should be taken with the specifications of the ram system for geothermal work. The temperature limits of 700°F for a worst-case analysis are well beyond the normal temperature limitations. The pipe rams and blind rams can probably be effectively modified for the most severe geothermal conditions yet experienced, but a testing program to check out the actual operation of rams under extreme temperature conditions might be prudent.

Figure III-13.

MAJOR FEATURES OF CAMERON TYPE
"U" BLOWOUT PREVENTERS

1. Forged Steel Body
2. Ram Packing
3. Hydraulic Piston
4. Bonnet Opening Piston
5. Ram
6. Hydraulic Fluid Passage
7. Wellbore Pressure Acts in this Area Under the Ram to Help Keep it Closed (Self-Energize)
8. Piston Seals
9. Ram Lock (Mechanical)
10. Operating Cylinders

Courtesy Cameron Iron

Figure III-14.
SHAFFER RAM PREVENTER
TYPE SL TRIPLE PREVENTER

All ram manufacturers make at least double units to save space. In the above unit, notice that the upper ram is a shear ram for cutting the pipe as well as sealing the open hole. The open bonnet in the center is a good view of the ram packing that would be subject to high well temperatures. Side outlets in the front of the picture are provided for pumping into the well under pressure.

Courtesy N. L. Shaffer

Accumulator System

The accumulator (or closing unit) system provides quick closing power for the BOP stack. The accumulator, which has a stored supply of hydraulic fluid under pressure, can shut the pipe rams in six seconds or less on surface-mounted BOP stacks. The pressurized hydraulic fluid in the accumulator acts much more quickly and reliably than would a pump system.

To operate the accumulator, simply push the control lever for the BOP to the closed position.

The system normally consists of a number of bottles (see Figure III-15) of fluid pressurized to 3,000 psi. The hydraulic fluid sent to the annular preventer goes through a regulator where it is regulated down to 700 to 1,000 psi and then is sent to the annular preventer. The hydraulic fluid that goes to the pipe rams goes from the bottles to a separate regulator where it is regulated to 1,500 psi and then to the rams. As the bottles are being discharged, a pressure-controlled switch starts the pump that recharges the bottles so that the pressure in the bottles stays near 3,000 psi.

The accumulator system is a 'must' for geothermal drilling. It allows rapid closing in of the well and, equally important, it allows remote operation of the BOP stack.

The only limitation to this system for geothermal drilling would be the selection of a proper high-temperature hydraulic fluid where BOP stack temperatures may get high.

Figure III-15.

ACCUMULATOR SYSTEM

1. Accumulators
2. Operating Valve
3. Pressure Gauges
Accumulators
Pipe Rams
Annular
4. Hydraulic Reservoir
5. Air-Operated Hydraulic Pump
6. Pressure Regulator Valve

Courtesy Koomey

Drill Pipe Safety Valves and Kelly Cocks

Drill pipe safety valves and kelly cocks are full-opening ball or plug valves that are used to stop flowback up the drill string if a well kick should occur. Figure III-16 shows one type of valve.

The drill pipe safety valve is usually stored on the floor in a sub that is equipped with handles for quick installation on the drill pipe. The drill pipe safety valve is used to stop flowback up the drill pipe when the kelly is disconnected.

The lower kelly cock is the same type of valve installed in a sub on the bottom of the kelly. It is used to stop flow up into the kelly, so that it can be disconnected, or to shut off the kelly to relieve pressure on the kelly, hose, and swivel.

The upper kelly cock is on the top of the kelly and is used as a secondary valve for relieving pressure on the kelly, hose, and swivel.

These valves would not normally be subjected to extremes of pressure or temperature. However, since they are designed as emergency equipment, they should be able to withstand a worst-case situation.

The valves should be checked for high-temperature clearances, greases, and sealing rings. The pressure capability of these valves is very good, but not all of the manufacturers have prepared for the high temperatures that may be found in geothermal drilling.

Figure III-16.

**KELLY COCK OR DRILL PIPE SAFETY VALVE
(TIW VALVE)**

Courtesy Texas Iron Works

Drill Pipe Inside BOP and Float Valves

The float and inside BOP are used like a safety valve to shut the drill string off so it will not flow, but they also allow pumping through the drill string. This is needed when running back in the hole under pressure. The float or "string float" is used in air or foam drilling to prevent decompressive flow back up the drill pipe on connections.

The string float, or bottom-hole float, is a simple, one-way valve (Figure III-17). The float is put in a sub just above the bit to prevent backflow into the bit. The string float is put near the top of the drill string in air or foam drilling.

What is generally referred to as an inside BOP (Figure III-18) is the releasable stabbing tool that is stored on the floor. It makes up on the top of the drill string and usually has some makeup handles on the top for easy handling. The sub is locked in the full open position on the floor by a pin or sleeve so that mud can backflow up the pipe while it is being made up. (It could not be made up against pressure otherwise.) After the pipe is made up tight, the pin or sleeve is removed and upward flow of the mud shuts the valve.

A third kind of inside BOP is the drop-in, or pump-down, tool. It is used when pipe is to be stripped from the hole under pressure or with wire line tubing operations. This tool requires a sub in the drill string, usually placed near the bit. The sub has a ring groove in which the element locks.

These tools need the addition of high-temperature O-rings and seals to be compatible with geothermal drilling.

Figure III-17.

FLOAT VALVES

PISTON TYPE FLOAT VALVE

Fits in drill string near bit to prevent backflow in drill bit.

FLAPPER TYPE FLOAT VALVE

Full opening valve used in drill string near bit to prevent backflow. Also used in air drilling as a string float (near the top of the drill string).

Courtesy Baker

Figure III-18.
INSIDE BOP

Automatic Inside BOP (Float Valve)
with Release Tool

INSIDE BOP for
drill string shut off,
but allows pumping
down.

DROP-IN INSIDE BOP

Drops down or pumps down
the drill pipe to a sub
located at the bit to shut
off flow in the drill
string.

Courtesy Hydril

Courtesy Gray Tool

Choke Manifolds

The choke and kill manifold (Figure III-19) is for the purpose of directing the mud or steam to the proper choke during a well kick. It allows alternate paths in case a valve or choke washes out, or allows flow directly to a separator or bypass line.

The manifold also provides a way of controlling pressures at the surface so the well can be tested or rig repairs can be made.

Manifolds tend to be an overlooked piece of equipment and somewhat of an afterthought, especially in geothermal drilling. The manifold should be designed for the pressures, flow rates, and functions that it needs to accomplish. While there are some suggestions on this subject in API RP 53, there is very little in the way of standard designs or design criteria.

The best of the manifold systems for geothermal drilling are the direct transfers from oil and gas drilling. Depending upon the test program while drilling, they may or may not be suitable for high-temperature work. It is quite probable that valving and tubular expansion problems encountered at high temperatures have not been considered. The problem of high-temperature seizing of plug and ball valves, and of stem packing on gate valves, needs to be examined at some length. Manifolds used in geothermal drilling tend to be minimal, and probably in most cases that would be adequate. In general, however, manifolds tend to be overlooked and there are few provisions for immediate changeover to well-control procedures. Valving in the 2,000 and 3,000 psi manifolds observed on geothermal wells is inadequate for high-temperature work, and

it can be expected that the stem packing will leak or blow out. Geothermal manifolds should not be equipped with , conventional adjustable chokes, since they have a tendency to seize at high temperatures. The whole subject of the choke manifold for geothermal drilling should be re-examined and the purpose and specifications for the manifold should be redesigned.

Figure III-19.

CHOKE AND KILL MANIFOLD

Adjustable Chokes

The remotely operated adjustable choke provides the easiest and most accurate way of controlling a well kick. SWACO and Cameron have the most commonly used remote operating chokes designed specially for well killing, and they are completely different designs. The remote operating panel provides a control center for well-killing operations and is a valuable addition to the choke. The adjustable choke and remote operating panel are important parts of modern well-control operations (Figure III-21).

Figure III-20
Conventional Adjustable Choke

The conventional adjustable choke is normally not suitable for geothermal work because it has a tendency to lock tight when heated (Figure III-20).

Figure III-21. Drilling Choke System.

There is limited data on adjustable choke operation above 300°F. It appears that either type choke can be equipped with Viton seals and probably operate in the 500°F range. The chokes used for geothermal and geopressure work should be equipped for high-temperature and a record kept of any use in extreme temperatures because it is difficult to duplicate the extreme pressure and temperature conditions under which the chokes would have to operate without creating an extremely hazardous test condition.

SWACO Super Choke

The Super Choke (Figure III-22) is a 10,000-psi (700 Kg/cm²) valve that operates by rotating one plate against another. The plates each have a "half moon" opening and as the openings rotate into line, the choke opens. The tungsten carbide plates slide against each other on a lapped surface so that the power used to rotate the plate is much less than the well pressure. It is a very efficient high-temperature choke, because the sliding plates are not temperature sensitive.

The choke plates are 1" thick and 3-1/4" in diameter. In full open position, the opening is equivalent to a 1-5/8" choke bean.

Cameron AX Choke

The Cameron AX Choke (Figure III-23) is a 5,000-psi or 10,000-psi choke. It uses a bar that moves in and out of a tapered choke gate. The movement is controlled by a double-acting hydraulic cylinder. The choking action is produced as the bar approaches and then enters the tapered seat. Clearances between the bar and seat in the choke are not critical, so it is an effective high-temperature choke.

Full open is equal to a 2" choke bean. The wear areas of the bar and seat are tungsten carbide.

Figure III-22.
SWACO SUPER CHOKE
Drilling Choke

Choke Console

Choke

Choke Cutaway

Figure III-23.
CAMERON AX DRILLING CHOKE

Choke Console

Choke Gate
Choke Seat

Choke

Mud Return Indicator (Flow Line Sensor)

A mud return indicator is usually a level indicator in the flow line. This may seem inaccurate, but it is a wier, and wiers are one of the oldest methods of measuring flow. The level indicator in the flow line reports the height of mud in the flow line. This signal is sent to the driller's console where it is reported as "percent of flow" or "gpm." Neither of these numbers is as important as a change in flow.

If a well kicks, something has entered the wellbore. This will push mud out of the flow line and will be shown as an increase in flow. So an increase in flow is the first sign of a kick, and the flow sensor is the first indicator of a kick.

The flow line sensor (see example in Figure IRI-24) is one of the weak links in the detection system for well kicks. There is a problem of sensor reliability that is probably a result of relatively low cost. Because the flow sensor is the first indication of a well kick, the system needs improved reliability. Flow sensor systems are a 'must' in geothermal drilling in fluid reservoirs.

Figure 111-24.

MUD FLOW-FILL & STROKE INDICATOR

Mud Flow-Fill Indicator shows return mud flow and mud pump stroke count.

Courtesy Martin Decker

Mud Pit Level Indicators

The pit level indicator in present usage adds up the volume in each pit and reports on a recorder and an indicator the total pit volume or a working pit level. Figure III-25 shows one type of indicator.

The pit volume indicator is a basic well-control warning instrument. A well kick pushes mud out of the hole and this is recorded by the pit level indicator as an increase in pit level or pit volume. So one of the warning signs of a well kick is an increase in pit volume. The driller's indicator has an alarm system that calls attention to pit change.

The pit volume systems are simple in operation. The height of the mud in each pit is measured. This height is then multiplied by the pit volume in barrels per inch or some like term.

The output of all the pits is then added together and reported on the chart and indicator. These measurements and calculations may be done either electrically or by air (pneumatically).

On most pit level indicators, the gain or loss of mud is indicated and alarms are provided to show gains or losses exceeding preset limits.

The mud pit totalizer systems lack reliability and are especially erratic in very hot muds. As with the flow-sensing systems, the accuracy is adequate but the systems are not reliable enough, especially when subjected to heat and steam.

Figure III-25.

Courtesy Martin Decker

Trip Measurements (Hole Fill-Up)

A basic safety measure when drilling with water or mud is to fill the hole with water or mud as the pipe is pulled during a trip. If the hole is not filled when the pipe is withdrawn, the bottom-hole pressure is reduced and the well may kick. Two basic measurement devices are used to measure hole fill-up when coming out of the hole and displacement when returning the drill pipe to bottom. They are the pump stroke counter, flow sensor, and the fill-up tank (Figures III-24 and III-26).

The pump stroke counter and flow sensor combination is the most common fill-up measurement device. During a trip, after a fixed number of stands of pipe is pulled, the pump is turned on at an idle speed. The pump stroke counter counts the pump strokes and when the hole fills up and flows down the flow line, the flow sensor turns off the pump stroke count. The count of pump strokes is a reasonably accurate method of determining volume of mud into the hole for a certain amount of drill pipe pulled. Often, cumulative pump strokes are retained for a more accurate overall look at fill-up. When going back in the hole, the flow sensor indicates that the pipe is displacing mud out of the hole and that the displacement stops between stands of pipe.

The pump stroke counter and flow sensor are adequate for most normal circumstances and, if rigorously followed, are accurate enough to prevent anything more than the smallest of kicks.

The most accurate measurements of hole fill-up and displacement are with the trip tank (Figure III-26). The trip

tank is a small tank from which accurate measurements of the mud pumped into the hole can be made. The best trip tank arrangements continuously circulate over the open hole and so keep the hole full. The measure of mud displaced versus the pipe pulled or run back into the hole is displayed on the floor in front of the driller.

Either of these systems can be used for geothermal drilling. The problem is one of reliability combined with an obvious and accurate floor readout. The technology is adequate for the purpose, but reliability and maintenance are serious problems.

Figure III-25-a. Pump stroke indicator for hole fill-up.

Courtesy Geolograph

Figure III-26.

TRIP TANK

Gas Detectors

Gas detectors (Figure III-27) on a rig have two general uses. The mud logger uses a gas detector to detect gas in the mud. Gas in the mud line may indicate that the rig is drilling a gas-bearing formation or that gas is feeding into the mud under pressure. If the gas at each connection--when it is circulated up to the surface--is much greater than when drilling, this is a sign that pressurized gas is entering the mud and perhaps the mud weight should be increased.

The area gas detectors on the rig are used to warn of gas concentration in places where an explosion or fire could occur.

Most of the new gas detectors use a catalytic burner to detect the presence of combustible gas. The catalytic element "burns" the gas, and the resulting heat changes the ability of a wire to conduct electric current. This change in current operates the alarm and recording system.

The gas detectors used as area detectors are quite suitable for geothermal usage, provided they are suitably packaged. H_2S detectors and flammable gas detectors are sensitive to moisture, so care needs to be taken when using them for mud-gas or blowie-line gas detection.

Figure III-27. Automatic recording gas detector.

Mud Cooler

It has repeatedly been pointed out in this report that the high temperatures likely to be encountered in geothermal well drilling can affect connections, seals, and clearances in well equipment and well-control equipment. This is particularly true with wells drilled with water or mud; the circulating fluid is heated to near-reservoir temperatures, which can reach 700°F. Obviously, a method of cooling the mud is useful.

One type of mud cooler is shown in Figure III-28. With this heat exchanger, which is used at Cerro Prieto, Mexico, mud is pumped in the top of the column and falls through a series of baffles to be discharged at the bottom. Air is counterflowed up the center. Water is injected at the top with the mud. This unit reduces mud temperatures about 20°C (36°F) in the desert environment of Cerro Prieto.

Figure III-28. Mud Cooler.

Cerro Prieto, Mexico

IV. JOB RESPONSIBILITIES, TRAINING, AND REGULATIONS

The defining of job responsibilities and formal training are not strong traditions in U. S. industry, and drilling people are no exception. The economics of failure and its natural selection process tend to weed out those who cannot learn rapidly enough to successfully fill a new position. Successful field practices developed through time and experience. The resolution of most of the problems and the practices required are generally well known, at least in the areas where the problems exist.

State Regulations

In general, the states have accepted this position and state laws tend to be more related to land use and to Workman's Compensation (safety) problems than to address such problems as well control specifically. The exception is in the state of California, where rules for geothermal drilling preceded Federal Regulations. The regulations parallel each other quite closely, and there appear to be no conflicts. The California regulations are more detailed, reflecting the concentration of geothermal wells in that state.

The State of California geothermal drilling regulations are published under the authority of the Division of Oil and Gas as part of the California Administrative Code. Geothermal Regulations are published under Title 14, Chapter 4, Geothermal Resources and Subchapter 4, Statewide Geothermal Regulations.

The State of California Geothermal Orders do not show the extent of actual involvement of area geothermal officers in

operations. The interpretation of the geothermal drilling orders is based on long familiarity with ongoing operations. The thrust of the state regulations is towards safe operations and methods of avoiding kicks. Since the operational areas are relatively small, the interpretation of the regulations can be site specific.

Federal Regulations

Geothermal well drilling on federal lands are covered by the "Geothermal Resources Operational Orders,"* which specifically list the drilling procedures to be followed. To these regulations are added the appropriate BLM and Forest Service regulations which apply mostly to environmental standards and do not generally impinge directly on the well-control operations.

The "Geothermal Resources Operational Order #2" is quite specific on equipment and testing, but somewhat less stringent on techniques and training. It is required that "A blowout prevention program"....be submitted with the "drilling program". There are no training responsibilities in geothermal work. Geothermal Resources Operating Order #2 states, "All necessary precautions shall be taken to keep all wells under control at all times, utilize trained and competent personnel, and utilize properly maintained equipment and materials...." (Order #2, paragraph 2).

In light of the different techniques and requirements for the various classes of geothermal wells, this is a reasonable approach. Unlike geopressure wells where the overpressuring makes it possible to have one fixed general procedure, geothermal wells are varied in their ability to hold even normal pressure and a standard procedure would be very difficult to achieve.

Thus the method for killing a well kick is left to the operator's drilling program. In most geothermal wells, this will amount to pumping cold water down the hole since the pressure gradient of most geothermal wells is less than the pressure exerted by a column of water. An exception to this rule may occur in

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the Roosevelt Hot Springs area of Utah where it is reported that pressures higher than normal have occurred. If this condition can exist in geothermal wells (i.e., pressures greater than normal), it would be desirable to utilize the constant bottom-hole pressure technique of well control used elsewhere.

Training

Well-control training is fully established for offshore continental shelf wells as a result of the USGS Order #2. Before that, oil companies and service companies had established formal schools and seminars as early as 1969. At present, the USGS-T 1 has formalized the school curriculum standards and there are a number of private and public schools in operation in the U.S. Figure IV-1 from the January, 1978, Oil and Gas Journal lists U.S. schools and students.

International training is somewhat less concentrated and more in the hands of private operations, so it is more difficult to check on the actual operation of the schools (which tend to be less of a fixed-base operation). Figure IV-2 lists information available on international training.

In the U.S. and internationally, most of the major oil companies and contractors have training schools for well control. These tend to be traveling schools that take the school to the operation or drilling rig. Figure IV-3 lists information available on these schools.

The data shown are probably incomplete. There is a great deal of effort on well-control training that is impossible to trace or document because it is not formally or publically reported. It should be noted, however, that almost all of this training is dealing with geopressured operations and the majority of it has to do with offshore or marine operations, not with geothermal operations.

U.S. offshore oil industry may face training crunch

A TRAINING crunch may be in store for the U.S. offshore petroleum industry as new employees and present drilling crews needing government certification line up at the classroom door.

New U.S. Geological Survey certification requirements for drilling operators and contractors working in federal waters pose two immediate problems to well-control trainers.

First, their courses must be certified before USGS will certify their graduates. Second, the new requirements will send many graduates now at work back to school.

So training programs, both company in-house courses and independent industry schools, are beginning to prepare for the USGS test and increased student loads.

Several schools are expected to apply for certification this month.

Student load. At least 5,000 persons working in U.S. federal waters will require the new certification. The number could be as high as 10,000, depending on individual company manning requirements and changeout policies.

During the next 23 months, industry will have to train 8,000 new students. And another 8,000 students will require refresher training. But requirements will be heavier than that because those figures assume zero turnover and diversions of all training for land contractors to the offshore market.

Industry's training capacity at present is about 12,000 students/year for all types of courses. Half of that training is provided by oil companies and contractors and the other half by industry schools led by colleges and drilling-mud companies.

Most popular schools appear to be those cosponsored by the International Association of Drilling Con-

Major schools*

Company	Total students trained	Stated capacity, (Students/year)	Cost (\$/man)
LSU	3,931	960	400
U. of Oklahoma	1,200	800	400
IMCO Services	7,000	1,100	Free
Dresser Magcobar	400	250	400
NL Baroid	200	500	300
Milchem	900	500	Free
Simtran	2,000	1,000	350+
International Training	New		
WOGA (Ventura College)	New	480+	
Prentice & Records (USL)	2,000	1,000+	385
Oil & Gas Institute	New	500	400
Petex	750	500	400
Total	18,381	7,590	

*Subject matter and duration vary.

tractors (OGJ, Sept. 19, 1977, p. 147). IADC-cosponsored schools that have trained more than 5,000 students include Louisiana State University, Baton Rouge; University of Oklahoma, Norman; University of Southern Louisiana, Lafayette; and Lamar Tech, Beaumont, Tex.

Other colleges are setting up schools, and many existing schools are expanding. Still, industry trainers say a student training crunch could come just before the USGS regulations take effect.

Adding to the training-demand surge are the cumulative requirements of USGS certification. For example, a tool pusher who wants to continue work as a tool pusher

after the regulation deadline must return to school and complete approved courses for rotary helpers, derrickmen, and drillers, as well as a course for tool pushers.

Industry effects. Even land-drilling contractors may feel the squeeze, as training capacity in non-OCS-related courses is shifted toward fulfilling the new USGS requirements and handling the student load.

Moreover, training will be increasingly expensive as schools strive to insure their students meet the USGS demands. That means contractors will have to exert closer control on turnover rates since they will have more money invested in each worker.

And if a training logjam does develop, contractors who start late in beefing up their training programs may find themselves short-handed.

School response. Spokesmen for several schools planning to expand their courses say they are worried whether there will be enough qualified instructors to handle the bigger programs. Time, paperwork, and investment requirements are heavier under the USGS rules, too.

And course developers are uncertain about some certification procedures. They don't yet know whether USGS will require written examinations. If so, some courses will have to add a day to their training times, reducing capacities.

Only one school, Prentice & Records, has applied for USGS certification.

The company says its application is modeled after that of a surface-safety school at the University of Southern Louisiana already approved by USGS.

Other schools say they are still studying the final standards and deciding how to handle paperwork.

Figure IV-1. Major U.S. well-control schools (from The Oil and Gas Journal, Jan. 16, 1978).

<u>Company</u>	<u>School Location(s)</u>
Exxon	Humble (Texas) King Ranch (Texas) As Required
Gulf	Houston, As Required
Shell	White Castle (Louisiana) As Required
Pan American Petroleum	As Required
Amoco	As Required
SEDCO	Rig Site
Loffland Bros.	Rig Site
Reading and Bates	Lafayette (Louisiana)

Figure IV-3. PRIVATE U.S.-BASED TRAINING SCHOOLS FOR WELL CONTROL
(Private schools that are operated on a formal
scheduled basis. Many more are operated on a
less-formal basis.)

<u>School Operator</u>	<u>Operated For</u>	<u>Location</u>
Petroleum Industry Training School	Canadian Industry	Edmonton, Canada
Payjak Land and Marine	Private	As Needed, Canada
Scottish Offshore Training Association	British Petroleum Training Board	Aberdeen (Montrose) Scotland
SNEAP	SNEAP	Pau, France
OSCO	Iranian Government	Awaz, Iran
Simtran	Zapata Drilling Company	Rotterdam, Netherlands
Reading and Bates	Reading and Bates	Malta
Shell International	Shell International	The Hague, Netherlands
Simtran	Private	As needed, International

Figure IV-2. INTERNATIONAL WELL-CONTROL TRAINING SCHOOLS.

PRACTICES AND PROCEDURES

In the absence of other guidelines, the following practices and procedures are suggested for the three major types of reservoirs.

Hot, Dry Reservoirs

There appears to be little blowout danger from hot, dry reservoir rocks, except that steam unloading could cause danger to the rig crew. This is, however, based on very limited experience but the possibility of unknown situations, however remote, does exist.

When air drilling, the rig is equipped with a drilling head and hot air is blown down the blowline or to a muffler/dust arrester. There appears to be little hazard involved in this operation as long as the drilling-head packer will divert the hot steam or water.

When water drilling or mud drilling, the fluid is cooled in the mud pits. Most rigs have tanks of water available that can be pumped into the well for cooling. Until more experience is available, it might be desirable to use a drilling head when bottom-hole temperature exceeds 350°F on "wildcat" wells to protect the crews from steam unloading. The problem of steam unloading of mud or water is very real as the well temperatures approach 700°F. The drilling head, flow line, and heat exchanger should be capable of containing superheated fluids until they are cooled.

When drilling with either air or mud/water it would be prudent, at least on "wildcat" wells, to have the standby water

tanks and pumps connected to both the standpipe and the annulus fill-up line with remote pump controls. The valving to the fill-up line and standpipe should also have remote controls.

The best plan and procedures cannot be implemented until the operating personnel know what to do and how to do it without detailed instructions. The operator's representative and tool pusher should be responsible for initiating functional drills for emergency procedures. The drills should be tourly until the crews can react within some reasonable time; thereafter, they should be on at least a weekly basis.

The purpose of the drill would be to assure that the driller and floor crew could react to such problems as failure in the drilling head rubber or steam unloading without the immediate supervision of the tool pusher or operator's representative. The drill should define the crew's actions, set a time limit for reaction, and be carried far enough to demonstrate that the driller knows how to accomplish his task and that the crew members know immediately what to do. The drill does not need to be carried through all steps.

Vapor-Phase Wells

There is more data on vapor-phase wells. Steam wells appear to have generally subnormal pressure, but the high volume of steam can release a great deal of heat.

When air drilling, a drilling head is employed and the steam and air are sent to the blooie line and then to a dust collector/silencer.

For directional drilling or when using stabilizers or drill string tools that cannot be stripped, the compressed air is generally diverted to the blooie line where it causes a vacuum that pulls the steam down the line away from the floor. This is satisfactory in most cases, but a diverter capable of stripping drill pipe, collars, and tools would give more positive protection to the crews.

The general practice is to have standby water tanks to kill the well if it gets out of control. These pits should be connected to the standpipe and annulus fill-up line through pumps with rig floor remotely controlled valves, and pump throttles.

Until more experience is available, it might be desirable to use a drilling head when bottom-hole temperature exceeds 350°F on "wildcat" wells, to protect the crews from steam unloading. The problem of steam unloading of mud or water is very real as the well temperatures approach 700°F. The drilling head flow line and heat exchanger should be capable of containing superheated fluids until they are cooled.

When drilling with either air or mud/water, it would be prudent, at least on "wildcat" wells, to have the standby water tanks and pumps connected to both the standpipe and the annulus fill-up line with remote pump controls. The valving to the fill-up line and standpipe should also have remote controls.

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Liquid-Phase Wells

Well-control practices for liquid-phase wells generally follow the basic steps of conventional oil-well drilling practices. "When in doubt, the well is shut in." Since no gas is present, the well fluids can be dominated by utilizing a constant casing pressure. This allows a well to be circulated and the mud weight increased.

The major problem in the water zones is lost circulation, however, so the buildup of any well pressure would be self-limited by loss of fluid (and pressure) to the formation.

The use of drill-pipe pressure in place of annular pressure might make some improvement in limiting the loss of mud to the production zone. While it would not produce significant improvement in safety, in the long run, it might be advantageous to use drill-pipe pressure techniques, since they are better suited to cope with uncertainties and changing conditions.

Until more experience is available, it might be desirable to use a drilling head when bottom-hole temperature exceeds 350°F on "wildcat" wells, to protect the crews from steam unloading. The problem of steam unloading of mud or water is very real as the well temperatures approach 700°F. The drilling head flow line and heat exchanger should be capable of containing superheated fluids until they are cooled.

When drilling with either air or mud/water, it would be prudent, at least on "wildcat" wells, to have the standby water tanks and pumps connected to both the standpipe and the annulus

fill-up line with remote pump controls. The valving to the fill-up line and standpipe should also have remote controls.

The best plan and procedures cannot be implemented until the operating personnel know what to do and how to do it without detailed instructions. The operator's representative and tool pusher should be responsible for initiating functional drills (practice) for emergency procedures. The drills should be tourly until the crews can react within some reasonable time; thereafter, they should be on at least a weekly basis.

The purpose of the drill would be to assure that the driller and floor crew could react to such problems as failure in the drilling head rubber or steam unloading without the immediate supervision of the tool pusher or operator's representative. The drill should define the crew's actions, set a time limit for reaction, and be carried far enough to demonstrate that the driller knows how to accomplish his task and that the crew knows immediately what to do. The drill does not need to be carried through all steps each time.

IMPROVEMENTS TO FIELD PRACTICES

It is difficult to rationally suggest improvements in well-control procedures for geothermal wells because the only blowouts that have occurred have resulted from very shallow steam (The Geysers, Suprise Valley), parted surface casing (Roosevelt Hot Springs), or landslide areas (The Geysers). Since present practice would not include drilling on top of an active steam fumerole, and since the casing and landslide problems are the result of thermal expansion and cementing -- and thus are outside the limits of this report, no useful new techniques for geothermal well control are obvious.

There are, however, some comments that can be made on technique. The comments relate to general good practices and might avoid some future problems.

1. In most geothermal drilling operations using mud, the problem of hole fill-up appears to be treated rather casually. There seem to be two reasons for this. First, the rigs are small and mobile and do not generally carry the trip tanks, pump stroke counters, and flow sensors that are necessary to check on fill-up. If the equipment is available, it is difficult to keep it in operation after repeated rig moves. Second, there are few obvious ill effects from not filling the hole. In most cases, the well will not and cannot kick. Therefore, there seems little reason to be concerned about hole fill-up.

Not filling the hole during a trip is recognized as one of the two primary causes of well kicks in oil and gas drilling, and even though there has been little evidence that kicks will occur in geothermal drilling, the practice of filling the hole

requires little extra effort for the additional safety that it provides. In addition to the safety, filling the hole tends to reduce pressure variations on the borehole and often helps prevent caving of the hole.

2. Choke manifolds on geothermal drilling operations where mud or water is used have been observed to be indifferently rigged up. The choke manifolds can and should be low-pressure, simple arrangements. They should be rigged with straight discharge lines. The lines should be restrained or staked down, and provision should be made for choked flow to go back to the mud pits, to the waste pit, or to an emergency discharge line.

3. The use of conventional adjustable chokes (needle valves) in geothermal choke manifolds should be discouraged until some evidence has been provided that the choke used will adjust at high temperatures.

4. If the method of well control is to be part of the drilling program, which seems reasonable considering the variety of geothermal regimes, then some provision should be made for each crew to hold a practice drill at least weekly. The drill should cover trips and drilling.

5. The operator's representative and tool pushers should directly supervise practice drills to be sure that the rig supervisor knows and can implement the well kill plan. This has been a weak point in other programs.

6. There is no clear definition of responsibility for crewmen and supervisors, except the implication that the operator bears overall responsibility. Some further definition

of the tool pusher's and driller's responsibilities might encourage more alertness.

7. The California rule of limiting exploratory drilling without a well-cemented surface string to mud/temperature below 75°C is an excellent way to prevent shallow steam blowouts. Under the California procedures, any time that the mud returns exceed 75°C when drilling heat holes, drilling must be stopped and the Geothermal Officer for the District consulted for a revision in the plan. The revision may consist of plugging the well, running casing, or some other option. This procedure is a simple, effective method for preventing shallow steam blowouts.

V. ECONOMIC CONSIDERATIONS RELATED TO WELL CONTROL

Blowouts are a wasteful manifestation of loss of control over subsurface fluids. The geothermal blowout, while it may be spectacular from the viewpoint of steam released, is at least a magnitude less costly and destructive than an oil or gas blowout. This is the natural result of less pressure in geothermal wells, less surface pollution, and the lack of fire. The potential for blowouts in geothermal drilling would naturally increase as more rigs drill deeper into higher pressures and temperatures. Awareness of the problem, however, will tend to limit practices conducive to blowouts, and the net result should be less rather than more well-control problems.

Blowouts in geothermal drilling are almost nonexistent. Shallow steam has caused a blowout in at least two cases. Present awareness and regulations tend to make it rather unlikely that shallow steam will be a significant factor in future well-control problems. Shallow steam problems will always be a factor in the drilling prognosis, but the advance warnings given by temperature measurements should make it significantly easier to detect than shallow gas.

Blowouts associated with landslides are a geological engineering problem that is solvable with good planning and well placement. The shearing of casing due to earth movement, as expensive as it may be, is not a drilling-related problem, and the dominance of this problem in The Geysers should not be allowed to affect unrelated drilling processes.

Casing and cementing problems in geothermal drilling are very real. Again, these are problems that have not been the result of drilling practices, except marginally.

The net economic result of blowouts, when geothermal drilling, is essentially zero up to the present time. Blowouts that have significant costs or cause significant damage or loss of life will probably occur at some point in future drilling. An increase in the number of drilling rigs, greater depths, and the higher temperatures and pressures make this inevitable. Most economic risks of geothermal drilling are in other areas than with the uncontrolled blowout, and reasonable prudence should keep them there.

Economic impacts of blowouts on the three major types of geothermal reservoirs are discussed in the following sections.

Hot, Dry Reservoirs

The only reasonable scenario for a blowout in hot, dry reservoir rocks, is steam blowing due to leaking casing, an exposed water bearing sand, or water injected into the hole as part of some drilling or completion process. This report envisions that the presence of significant H_2S in hot, dry holes is unlikely.

If prudent practices are used, and if the hole is never left open once the bottom-hole temperature exceeds $250^{\circ}F$, there should be no damage or loss from this problem.

A worst-case analysis would be the steam blowing to the rig floor and harming the rig crew. This could happen only if the pipe was being pulled or run into the hole with no protective "stripping" safeguard. An economic estimate of this event for the purpose of establishing priorities would be a probable cost of $\$0.5 \times 10^6$ based on the costs of landslides at The Geysers.

Vapor-Dominated Reservoirs

The scenario for blowouts from vapor-dominated reservoirs must take into account two blowouts that have occurred with shallow steam, the Thermal #4 at The Geysers and Wairakei #204 in New Zealand. In both of these blowouts, no major damage was done to the drill rig and there were no major injuries. The greatest cost at The Geysers was earth work to try to find the wellbore. In New Zealand, the major expenditures were for grouting the earth and drilling a directional kill well.

A minor well kick or blowout when drilling a vapor reservoir would probably be the result of failure in the drilling head packer element. The problem would be resolved by closing the pipe rams and changing the stripper or rotating head rubber. The cost would be a maximum of four hours of rig time. If an average of 10 geothermal rigs were operating at any time, it might be hypothesized that this would occur twice a year on each rig. Thus,

$$20 \text{ events} \times 4 \text{ hours} \times \$200/\text{hr} = \$16,000 \text{ year}$$

A major blowout while drilling a vapor-pressured well could be modeled after the Thermal #4, Wairakei #204, and some of the experience with Union Oil's GDC 65-28 at The Geysers (GDC 65-28 was a landslide-related problem). Based on these experiences, it can be postulated that a major blowout would not involve the loss of the rig or major injuries. In the worst case, the hole would be lost, requiring extensive site work and re-drilling or, more probably, directional hole. Costs involved would be the re-drilling of the hole, site work at the old location, and reassignment or personnel for supervision, monitoring, and administrative tasks. Costs can be estimated as followed.

Redrilling cost	\$ 1.5×10^6
Site costs	0.5×10^6
Administrative	<u>0.5×10^6</u>
Total	\$ 2.5×10^6

The frequency of the event is difficult to estimate, since operational procedures have been changed to avoid such incidents

Liquid-Dominated Reservoirs

The economics of blowouts in liquid-dominated reservoirs must take into account the experience in the Imperial Valley and the Mexican experiences at Cerro Prieto. In both of these situations, the incidence of blowouts is essentially zero. This is especially striking because the original equipment used at Cerro Prieto was old, undersized for the task, and initially operated by relatively inexperienced crews. (This is no longer the case.)

A speculative look at the problem would seem to indicate that a minor blowout would involve only the loss of some rig time, probably for steam unloading of the well, caused by superheating of the drilling mud. At the low pressures prevailing in the Imperial Valley, the problem would be self-limiting. At the higher pressures indicated at Roosevelt Hot Springs, Utah, unloading could lead to a full-scale blowout. A blowout or unloading could be stopped by closing the rams. The cost would be six hours of rig time to mix mud and clean the location. The frequency would be very low; a worst case would be to assume two incidents per year. Thus,

$$2 \text{ events} \times 6 \text{ hours} \times \$200/\text{hr} = \$2400/\text{yr}$$

A worst-case analysis would be to assume that the well could not be shut in because of some failure. For example, the driller tries to shut the pipe rams on a tool joint or on the drill collars. The hole would flow and steam unload. Large volumes of hot salt water would have to be disposed of and the immediate location would be covered with salt water. The hole could probably be killed with pump trucks and mud from the surface, but a worst case would assume that the killing caused

an underground blowout requiring a directional hole to kill the well. An estimate for this event is:

New Hole Cost	$\$1.5 \times 10^6$
Site Cost	1.0×10^6
Administrative	<u>0.5×10^6</u>
Total	$\$3.0 \times 10^6$

For frequency of blowouts see Geothermal Blowout Control Phase II.

VI. RECOMMENDATIONS

Listed below are recommended areas for improved training, equipment, and procedures for geothermal well drilling.

1. Drill crews and supervisors on geothermal liquid-phase wells should successfully complete well-control courses in the constant bottom-hole pressure technique modified after GSS-OCS-T 1.

2. Drilling crews and supervisors on all geothermal wells should practice well-killing or control procedures suitable to the reservoir and location until proficient and thereafter at least once a week.

3. A light stripping head utilizing a metal or nonelastomer plate should be developed for tripping. This head would not seal tight for pressure integrity, but would be a deflector to protect the rig crew. The new Cameron annular preventer, shown below, utilizing only very high temperature elements, is suggested as one idea.

Figure VI-1. New Cameron annular preventer.

4. The heat exchangers now used in mud drilling are adequate for present operations, but extension of present trends indicate that a closed system capable of handling muds above the normal boiling point (to avoid steam unloading) would be a major asset. A number of commercial heat-exchanger systems appear to have promise, notably the plate-type exchangers, and the technology should be aggressively pursued.

5. Standard well-control equipment should be tested against worst-case geothermal conditions for suitability of design and components. A project should be devised to develop this data from the manufacturer wherever possible and by test data when not available from the manufacturer. Standards developed in this project would help the manufacturer develop suitable equipment.

6. Standard well-control instruments should be tested against worst-case geothermal conditions for suitability of design and components. A project should be devised to develop this data from the manufacturer wherever possible and by test data when not available from the manufacturer. Standards developed in this project would help the manufacturer develop suitable instruments.

7. The drilling and stripping head is the heart of geothermal well-control operations. A long-term, and possibly low-key, project should be initiated as a joint industry/DOE project to guide the development of the drilling and stripping head for the high temperatures anticipated in future operations. While extensive research is going on in high-temperature elastomers, the result of this work is uncertain. It would be well to have a fall-back design if the present research is unsuccessful.

8. A remote operated geothermal drilling rig should be developed for future very hot holes. The rig would provide crew safety and added blowout control reliability by removing the operating personnel from the high-temperature area.

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GEOPRESSURE BLOWOUT CONTROL

**PHASE I
STUDY OF EXISTING TECHNOLOGY**

by

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prepared for

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FOREWORD

The following report is part of "A STUDY OF TECHNOLOGY IN WELL CONTROL FOR GEOTHERMAL AND GEOPRESSURED WELLS" prepared for The Department of Energy under Contract No. EG-76-C-07-1603, Modification No. A003.

There are four reports in the series:

1. Geothermal Well Control;
2. Geopressure Well Control;
3. A Program Plan for R&D in Geothermal Well Control;
4. A Program Plan for R&D in Geopressure Well Control.

The purpose of this study is fourfold:

1. Assess the present state of technology in well control relating to geothermal and geopressure wells;
2. Propose improved operating methods;
3. Propose improved equipment;
4. Develop a program plan of research and development necessary to assure safe and acceptable operating methods and equipment.

The project has been divided into separate areas for geopressure and geothermal drilling so that the problems of each area may be addressed in a more logical manner. Therefore, some of the material that is common to both areas will be repeated in the report.

The state-of-the-art in any type of operation is a moving definition. The cutoff date in this report series is information that was available in the first quarter of 1978.

GEOPRESSURE BLOWOUT CONTROL

SUMMARY

Geopressure drilling is hazardous because of the pressures and gas that will be encountered. The hazard is compounded by the great depth of the wells and the difficulty in properly interpreting the well conditions. The present state-of-the-art provides no guaranteed safe and assured manner to drill the very high pressured geopressured well. Safeguards do exist that reduce the hazard to what has been economically acceptable.

The equipment, techniques, and guidelines that have been developed for drilling into high pressure and geopressured zones are complete and adequate for their purpose - drilling for high pressured oil and gas fields.

Equipment to detect the potential blowout in its earliest stages is unreliable and needs improvement.

The standards on well-control equipment do not encompass the higher temperatures postulated for geopressure water and gas production and so the temperature limits need to be examined.

The real key to geopressure drilling lies in well site supervision and well programming. These are harder to grasp problems than equipment limitations, but the pressures from the geopressured well are so great (10,000 to 20,000 psi) and the problem of sand erosion of equipment is severe, that the geopressure well must be controlled at all times.

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I. CAUSES OF WELL BLOWOUTS

INTRODUCTION

A blowout, in the strictest sense, is an uncontrolled flow from a wellbore. Blowouts develop from a lack of balance in the fluid system used to carry debris or cuttings from the wellbore. Ordinarily, the weight of the fluid system balances anticipated formation pressures, thus controlling the well. Excessive overbalancing must be avoided, however, to prevent downhole problems and even loss of the drilling fluid to the subsurface formations.

As long as adequate records have existed, there have been blowouts when drilling wells. Water wells have provided some spectacular artesian spouts. Stories of oil-well drilling in the early 1900s detail the blowouts at Spindletop, Signal Hill, and Oklahoma City. These were small compared to the Cierro Azul blowout in Mexico, the great blowout in Romania, and blowout problems in the Middle East fields by British Petroleum. Blowouts that occurred in the early oil fields were considered a natural way of producing a well, or at least an unavoidable problem.

The cable tool rig made it difficult, if not impossible, to control a high-pressure well. However, with the advent of rotary drilling and circulating mud systems, it was practical to control earth pressures, and by the early 1900s blowout preventers were being developed that could close in a well but still allow circulation of the mud system (Figure 1-1). Numerous API Technical Drilling Papers between 1930 and 1960 discuss avoiding blowouts and blowout control equipment.

Figure 1-1. Decker 1903
Blowout Preventer
(after Brantley)

Responding to the obvious need for heavier drilling fluids that would control pressures, in 1932 National Lead Company formed its Baroid Division to provide barite ore to help increase the density of drilling mud.

The major breakthrough in well-control technique came with the paper of O'Brien and Goins in the API reports in 1960. The background and need for well-control techniques were further clarified in 1965 by (Hottman and Johnson's) on the

detection and measurement of formation pressures from well logs. Since then technology and equipment have developed rapidly and have been accepted throughout the petroleum-drilling industry. The blowout is now a rare but expensive event.

Water-well drilling and mining exploration have adapted the oil-well drilling concepts where high-pressures are involved or where some danger exists. However for the most part, the technology and equipment for well control remain within the oil- and gas-well drilling industry.

As exploration and exploitation of geopressure resources grow, a close look should be taken at transferring technology of well-control methods and equipment from oil- and gas-well drilling to geopressure drilling.

BASIC CONCEPTS

The basic requirements for blowout-control procedures and equipment in geopressured wells are:

- The water, steam, gas or other formation fluids must be controlled to prevent casualties among the rig crew.
- The environmental interest must be protected.
- The reservoir must be protected from damage or waste.
- Fresh water sources must be protected.
- The rig equipment must be protected from unreasonable wear or destruction.

These requirements indicate that formation fluids must be dominated and controlled without exerting high wellbore pressures that could cause fracturing of the earth or equipment failure.

The mechanisms of geopressuring and fracturing are well established by oil and gas operations. "Super pressure" wells proposed for geopressure drilling should follow oil field-technology transfer quite closely. The limits to technology transfer are more in the realm of extra care due to approaching the ultimate limits of equipment and casing than in need for development of new techniques.

Experience has already indicated that the temperature rating on surface and subsurface equipment may be optimistic. Some of the experiences on the D.O.E. Delcambre, La. well where surface equipment partially failed at temperatures below rated values have indicated the equipment normally used may be a problem with high temperature fluids.

A careful analysis of equipment, care in not forcing the ultimate pressure, and extended training are the keys to successful geopressure well drilling.

WELLBORE PRESSURES

High wellbore pressures develop from:

1. Differential Fluid Column Pressures
2. Geopressured Reservoirs
3. Improper Use of Pumps and Chokes
4. Improper Control of Gas Expansion in the Wellbore

1. DIFFERENTIAL FLUID COLUMN PRESSURES have been responsible for some of the unusually high pressures in oil and gas wells in the Southwest United States. In large structures of that area, the gas cap and underlying oil are balanced against an equivalent column of water. The overbalance of the water column over the oil and gas creates an abnormally high pressure. This pressure differential also commonly occurs in dipping reservoirs caused by rising salt domes; a similar condition occurs where aquifers extend to elevations above the ground level at the well. In water wells, this pressure differential causes artesian wells.

ARTESIAN FLOW

Figure 1-2

The same mechanism that causes artesian flow also causes abnormally high formation pressures in large structures in the earth. The balance of a column of air or gas against a fluid (water or oil) causes the fluid column to be pressured on the lower end such as in the artesian flow figure above and the gas (if it is confined) to be pressured on the upper end.

2. GEOPRESSURED RESERVOIRS are partially sealed during deposition so that the fluid supports some of the overburden pressure.

Figure 1-3

GEOPRESSURED RESERVOIRS

The lower limit of geopressure is normal pressure equal to a column of water from the point of interest to the surface. This is about .43 psi/ft for fresh water and .465 psi/ft for marine deposition.

The upper limit of geopressures is normally the weight of the overburden (about 1 psi/ft). Occasionally in hard rock, there are somewhat higher pressure gradients. In these cases, the density of the rock may be greater or there may be an arching mechanism involved.

The upper limit of geopressures in the Louisiana and Texas Gulf Coast is 0.90 - 0.95 psi/ft, the weight of the overburden in that area.

3. **IMPROPER USE OF PUMPS AND CHOKES** can induce unusual hydraulic pressure. A drill rig pump capable of 2,000 to 3,000 psi or a pump truck capable of 10,000 psi can impose pressures of these magnitudes on top of normal fluid pressure. Fracturing of the wellbore from induced pressures is one of the commonest problems in well control. The relationship between pressures on the formation caused by the drilling mud and pressures on the formation caused by induced surface pressure are not always clear to the man on the rig.

In the schematic of the well shown below, it is reasonably clear that the pressure on the casing side of the well is high enough that the formation pressure could be fractured with very little induced pressure from the pump and choke. However the well must be circulated to kill the kick. The problem is how to handle the mechanical equipment.

Figure 1-4

4. IMPROPER CONTROL OF GAS EXPANSION. The general gas law shows that pressure in a gas bubble is controlled by expansion (volume), temperature, and the gas type.

$$\frac{P_1 V_1}{T_1 Z_1} = \frac{P_2 V_2}{T_2 Z_2}$$

or

$$PV = nRT$$

Gas brought to the surface without expanding causes unusually high pressures in the well because gas carries pressure with it. On the other hand, uncontrolled expansion causes lower pressures in the wellbore because of the unloading of the mud column and then increased fluid flow from the formation.

GAS EXPANSION

Gas rising (Perculating) without proper surface pressure control unloads hole and causes further kicks

Gas rising (Perculating) without being allowed to expand increases pressure and finally causes lost circulation

Gas rising (Perculating) and drill pipe pressure kept constant by releasing mud at the choke keep everything under control

Figure 1-5.

CAUSES OF BLOWOUT IN GEOPRESSURED WELLS

The geopressured well is the ideal candidate for a blowout. It has high pressures and high permeability; hence there is high reservoir flow and enough gas to cause pressures from gas expansion. In addition, the danger of fire is always present.

The Formation

The geopressured or superpressured formations along the U.S. Gulf Coast can be expected to have pressure gradients up to 0.95 psi/ft. Since the typical Miocene or Oligocene high-pressured sands occur from 12,000' to 18,000', the general order of pressures will be from 10,000 to 16,000 psi. Pressures of this magnitude must be handled carefully to avoid their appearance at the surface since they approach the yield limits of mild steel.

The temperatures that will be encountered approach 300-400°F. Temperatures of this magnitude can cause problems with equipment on the surface since the mud circulated up from the bottom can still have temperatures in excess of 200°F.

The mechanism of geopressuring is a partial seal formed during deposition that stops upward migration of water from the shales and sand. Normally, shales are deposited as fine-grained sediments containing up to 80% water. As deposition continues, compaction occurs forcing water to the surface. Excess water is released through the mechanism called diagenesis.

Eventually the formations may compact to contain as little as 10-15% water at 18,000' (Figure 1-6). In geopressed formations, the seal formed during deposition prevents the expulsion of water. The seal may be chemical (CaSO_4 , CaCO_3), or mechanical (finer grained silts or faulting) or a combination of these seal types. The result is that the geopressed formation has excess water and the mechanism of geopressing is that the water in the formation supports the overburden loads.

The sands of the geopressed zones have high permeability and porosity. In particular, the superpressured zones, where the water is bearing all of the weight of the overburden, have reservoirs with very high initial flow rates. The combination of high pressure and high flow rate with gas can cause a blowout to develop rapidly.

Gas Unloading of a Well

The large gas production from reservoir sands adds a major dimension to the problems of controlling these wells. While in the reservoir, gas (mostly methane) is normally above its critical temperature and pressure. Thus it tends to act like a fluid until it is produced into the wellbore. During drilling operations, the gas typically starts to exhibit the characteristics of gas expansion when it has traveled up the wellbore to a depth of 8,000 to 10,000'.

At this time, it starts to expand according to the general gas law, and the well starts to unload mud out of the wellbore. As mud is unloaded, pressure on the gas becomes less and the gas expands more quickly. This leads to a chain reaction

THE CLASSIC REPRESENTATION OF SHALE COMPACTION

Schematic Representation of Shale Compaction (After Terzaghi and Peck)

- λ = Matrix Stress
- S = Overburden Load
- p = Formation Fluid Pressure
- D = Depth

Figure I- 6.

which can quickly cause a blowout from an initially small influx of gas into the wellbore (Figure 1-7).

The gas will expand (from 50 to 250 times its original wellbore volume) under these conditions. Therefore, an influx of 1 barrel of gas into a wellbore, which might not be noticed, could unload a significant volume of mud from the wellbore causing the mud pressure to drop far below the reservoir pressure. This would lead to a well kick - the beginning of a potential blowout.

Figure 1-7

Shallow Gas

One of the historical problems of well control has been shallow gas and water under geopressured conditions. Until enough casing has been set and cemented, it is impossible to stop the flow of fluid from high-pressure shallow formations with blowout preventers. With shallow casing, the high-pressure formation fluid breaks out around the casing.

In soft formations, 2,000 to 3,000' of casing is required to protect the rig from surface breakout of the formation fluids. Until that depth is reached, some method of surface diversion is required in place of closing in the well.

Normal protection - and in fact, the only protection - is heavy mud. However, there is a fine line between mud heavy enough to control pressure and mud so heavy that it causes lost returns.

Even with normal-pressure shallow formations, drilling gas sands too rapidly can lead to gas unloading the well.

Lost Circulation - Underground Blowouts

When insufficient casing is set above a geopressured reservoir, a well kick can turn into an underground blowout, Figure 1-7. When the required mud gradient exceeds fracture pressure gradient, lost circulation occurs. Fluid flow from geopressured sands into the upper fractured formation then occurs.

Most underground blowouts result from insufficient casing while drilling into geopressured sands using insufficient mud

density. The imposition of surface pressure to the mud column is necessary to stop a kick. The combination of surface pressure and mud column pressure may exceed the fracture pressure and cause an underground blowout. To avoid this problem, casing must be set into the top of the geopressured zones since formation fracture pressure follows formation pressure.

FRACTURING ABOVE GEOPRESSURES

Figure 1-8.

Equipment Limitations That Have Led to Blowouts

Available blowout control equipment for geopressured wells appears to be adequate for the proposed near-future wells. There is little evidence that equipment failure is the major cause of blowouts while drilling wells; the few equipment-caused blowouts have been produced by improper use, testing, or maintenance of available equipment. The obvious exceptions are the deep sour-gas wells in the Piney Woods area of Mississippi since the extreme pressure, temperature, and the presence of H_2S can easily lead to equipment failure.

In general, the basic equipment used for geopressure well control is adequate for the job. This equipment is reviewed in some detail in Task 3 of this report - "Well-Control Equipment." The BOP stack, and the chokes and choke manifolds have performed well and have been the cause of only minor difficulties.

Less attention is paid to the kick detection equipment than to any other equipment for geopressure drilling. As a result, it is possible to attribute a reasonably large percentage of well blowouts to failure of the detection equipment. Detection equipment comprises mud flow sensors, mud-pit level indicators, and trip tanks or trip counters for checking mud displacement when tripping drill pipe. Figure 1-9 is an example of a commonly used mud pit volume totalizer.

Presently, the detection equipment is the weakest part of the well-control equipment system. Since the equipment is unreliable, the driller often is casual about maintaining the warning system.

Generally, detection equipment is poorly used on drilling operations, and indifferently used or not used at all on completion and workover operations.

MUD PIT LEVEL INDICATOR

Figure 1-9.
Courtesy Martin Decker

- 1 - Drill Floor Panel
- 2 - Alarm Set
- 3 - Pit Float
- 4 - Chart
- 5 - Read Out

Prediction equipment for well kicks or blowouts is largely nonexistent. However, prediction techniques for well kicks are well documented and are usually carried on by mud logging units.

Procedural Failures That Have Led to Blowouts

Procedural failures in basic well-control techniques have been the major problems leading to blowouts. Within the last several years, extensive steps have been taken to try to reduce these problems. Supervisory and crew training, drills, and increased emphasis on blowout control have all been part of this effort.

Another problem relating to technique is failure to keep the hole full while pulling pipe or tubing out of the hole. Various reports indicate that between fifty and sixty percent of the well kicks occur while pulling pipe. This results from a basic procedural error and should seldom occur.

Failure to set casing at the proper point in geopressure drilling has caused well kicks to turn into blowouts. The technology required to predict casing setting depth in geopressured formations is new within the last 10 years and rapid strides have been taken to eliminate casing depth errors.

It is difficult to be precise in the documentation of procedural errors. Procedural errors set up the chain reaction that, sooner or later, leads to equipment failure or loss of the well through downhole conditions. The reporting process emphasizes the final failure, not the preceding errors.

Conclusion - Geopressured Wells

Blowouts or well kicks in geopressured wells are most commonly caused by:

- a) Inadequate detection equipment;
- b) Ignoring warning signals of well kicks (prediction);
- c) Inadequate crew training on well control;
- d) Improper casing points;
- e) Inadequate hole fill-up on trips.

II. WELL-CONTROL PROCEDURES

WELL-DESIGN

To successfully handle kicks when drilling geopressures, there must be adequate well design. Although techniques for this are highly developed, they are sometimes poorly applied. Successful handling of kicks depends on sufficient mechanical strength of the tubular goods and exposed formations to withstand the wellbore pressures developed.

Generally, formation strength increases with depth. Surface casing must be set deep enough for the formation to withstand the increased pressure gradients of the drilling fluid needed for geopressured intervals. In addition, the casing must be able to withstand the temporary increase in wellbore pressure while handling the kick. Failure to design the shallow part of the hole adequately can result in loss of circulation, underground blowouts, or breaching of the formation fluid through the upper formations to the surface.

There are also limits to the amount of geopressured interval that can be drilled before setting intermediate casing. This is necessary to limit potential increases in wellbore pressure in the exposed hole. Also high-pressure differentials developed on low-pressure formations can result in differential sticking of the drill string. Methods are available to estimate geopressures before drilling and to determine pressures during drilling. These, when properly used, allow correct setting of the casing as related to the previous casing string and the geopressured formations.

As geopressured intervals are drilled, the amount of overpressure often increases making necessary a second intermediate string of casing or a liner to protect against excessive pressure below the first intermediate casing.

WELL-KILLING TECHNOLOGY

The existing state of technology in well control is capable of handling well kicks when drilling for geopressures. The land drilling crews have not, however, been very extensively trained in this technique. There is almost no special technology developed for workover or completion crews. Therefore, workover crews are unprepared to undertake any well control beyond pumping down the well to force well fluids back in the formation and circulating drilling fluids for cleanup.

Well-control procedures are based on pumping or circulating a well under pressure by using a choke on the annulus. Well control is accomplished by using the choke to force the pump pressure to remain high enough to pressurize the hole. The pressurization of the hole is equivalent to, or higher than, the pressure required to dominate the reservoir.

Mud weight is substituted for surface imposed pressure. The increased mud weight or density is calculated according to the basic equations:

$$P = D \times Wt \times f \quad (\text{Eq. 11-1})$$

where

P = Pressure of Mud Column

D = Depth

Wt = Mud Density

f = Units Constant

from which

$$(\Delta)Wt = \frac{P_2}{D \times f} \quad (\text{Eq. 11-2})$$

where

$(\Delta)Wt$ = The increase in mud density to be distributed through the hole.

P_2 = The shut-in surface pressure on the drill pipe which is full of mud.

So in simplest form, a well is killed by these steps:

- 1) Shut in BOP when an increase in flow, or pit level, is seen.
- 2) Read and record the shut-in pressures on the pump gauge (the drill pipe gauge) and casing gauge.
- 3) Use Eq 11-2 to figure an increased mud weight, and mix that mud weight in the pits.
- 4) Open the choke and start pumping at a slow rate - the kill rate - where the pump pressure is already known. This pressure/rate relationship is measured by the crew each tour.
- 5) Adjust the choke to keep the casing pressure the same as when shut in. At this time, the pumping pressure should be equal to the known pump pressure at the slow rate plus the shut-in drill pipe pressure. As the heavier mud is pumped down the drill pipe, the drill pipe

pressure is reduced. This reduction continues until the new mud reaches the bit, and the final circulating pressure is on the pump (drill pipe) gauge. The final circulating pressure is:

$$\text{F.C.P.} = \text{The Kill Rate Pressure} \times \frac{\text{new mud wt.}}{\text{old mud wt.}}$$

- 6) Continue to pump at the kill rate and hold the final circulating pressure on the drill pipe pressure gauge with the choke. Do this until the well is dead.

A number of details (relating to how to obtain the initial circulating pressure and when to increase the mud weight) in the preceding steps are often varied. However, these variations do not change the method nor the results significantly.

This technique for killing the well - "the constant drill pipe pressure" or "constant bottom-hole pressure" method - is the best way to circulate an intrusion out of the hole and to replace surface pressure with mud pressure. The following Well-Control Work Sheet is a proposed API standard form.

In geopressure drilling, every effort should be made to react quickly to avoid the large kicks that could come from permeable salt water reservoirs. Unintentionally penetrated gas reservoirs also could cause large kicks and even greater well pressures. Avoiding these problems will require more accurate use of detection and trip fill-up equipment.

Since hot salt water can be expected to upset the drilling mud, the killing techniques should involve a comparison of the calculated initial circulating pressure and the rig-developed initial circulating pressure. The lower value should be used after a 10 minute period (Steps 4 and 5 in the preceding discussion). The constant casing pressure start-up should be carefully practiced to allow "breaking" circulation after a down period.

WELL CONTROL WORK SHEET

WAIT & WEIGHT METHOD

PROCEDURE

I. PRERECORDED INFORMATION

Casing: Size _____ in Weight _____ ppf Grade _____ Internal Yield _____ psi Depth, TVD _____ ft
Maximum Allowable Casing Pressure: _____ psi
Use lesser of: 80% of Casing Yield _____ psi, Fracture Pressure Limit (1) _____ psi, Other _____ psi
Normal Circulating Rate and Pressure _____ psi at _____ stks/min and _____ bpm at _____ ppg and _____ ft
Kill Rate and Pressure: Pump No. 1 _____ psi at _____ stks/min and _____ bpm at _____ ppg and _____ ft (2)
Pump No. 2 _____ psi at _____ stks/min and _____ bpm at _____ ppg and _____ ft (2)
Drill Pipe Capacity: _____ bbl/ft Approved By _____

II. IMMEDIATE ACTION

When a kick occurs, stop rotary, raise kelly, stop pump, open choke line and choke (if closed), close BOP, close choke while observing casing pressure. Do not let casing pressure exceed maximum allowed (3)
Closed-in Drill Pipe Pressure _____ psi, Casing Pressure _____ psi, Mud Weight _____ ppg, Depth, TVD _____ ft
Size of Kick _____ bbl.

III. INCREASE MUD WEIGHT

Calculate required mud weight (4) and increase weight in suction pit (5), (6)

IV. PREPARE DRILL PIPE PRESSURE SCHEDULE

Determine Initial Circulating Pressure and plot above zero time (7)
Determine Final Circulating Pressure (8) and plot above circulating time to bit (9)
Draw line between points
Read Drill Pipe Pressure at 5 minute intervals and record in blank spaces
Calculate strokes and fill in blanks (10)

V. ESTABLISH CIRCULATION

Open choke while bringing pump up to Kill Rate. Increase pump rate slowly, if possible
Adjust choke to hold Casing Pressure constant at Closed-in value while bringing pump to Kill Rate. Hold Kill Rate.
The Drill Pipe Pressure should be the sum of the Kill Rate Pressure plus Closed-in Drill Pipe Pressure.
If not correct, adjust. Record time circulation started.

VI. CIRCULATE HEAVY MUD

Maintain mud density in suction pit while circulating at Kill Rate
Use choke to adjust Drill Pipe Pressure to values shown at times or strokes shown
If Drill Pipe Pressure increases open choke, if Drill Pipe Pressure decreases close choke
When heavy mud reaches bit (9) (10), hold Drill Pipe Pressure constant until heavy mud reaches surface
When uncut mud of required weight reaches surface, stop circulation and check for flow

WELL CONTROL WORK SHEET WAIT & WEIGHT METHOD

CALCULATIONS AND NOTES

- (1) Fracture Pressure Limit = $.052 \times \text{Casing Depth} \times (\text{Fracture Mud Weight} - \text{Present Mud Weight})$
 = $.052 \times \underline{\hspace{2cm}} \text{ ft} \times (\underline{\hspace{2cm}} \text{ ppg} - \underline{\hspace{2cm}} \text{ ppg}) = \underline{\hspace{2cm}} \text{ psi}$
- Fracture Mud Weight = $\frac{\text{Leak off Pressure}}{.052 \times \text{Casing Depth}} + \text{Leak-off Test Mud Weight} = \frac{\underline{\hspace{2cm}} \text{ psi}}{.052 \times \underline{\hspace{2cm}} \text{ ft}} + \underline{\hspace{2cm}} \text{ ppg}$
 = $\underline{\hspace{2cm}} \text{ ppg}$
- (2) Measure at beginning of each tour, after drilling 500 ft. and after each change of over 0.1 ppg mud weight
- (3) If casing pressure reaches maximum allowed, stop closing choke, resume circulation at maximum rate, hold maximum allowable casing pressure and start increasing mud weight. Mud weight required is estimated from maximum drill pipe pressure observed before circulating. See Low Choke Pressure Procedure.
- (4) Required Mud Weight = Present Mud Weight plus $\frac{20 \times \text{Closed-in Drill Pipe Pressure}}{\text{Depth, TVD}}$ plus Trip Margin*
 = $\underline{\hspace{2cm}} \text{ ppg} + \frac{20 \times \underline{\hspace{2cm}} \text{ psi}}{\underline{\hspace{2cm}} \text{ ft.}} + 0.3 \text{ ppg}^* = \underline{\hspace{2cm}} \text{ ppg}$
- (5) If two sections or two pits are weighted and circulation established between, mud weight is more evenly controlled while circulating hole.
- (6) If drill pipe pressure increases during weighting reduce to initial stabilized value by bleeding casing pressure through choke.
- (7) Initial Circulating Pressure = Kill Rate Pressure plus Closed-in Drill Pipe Pressure
 = $\underline{\hspace{2cm}} \text{ psi} + \underline{\hspace{2cm}} \text{ psi} = \underline{\hspace{2cm}} \text{ psi}$
- (8) Final Circulating Pressure = Kill Rate Pressure x $\frac{\text{Required Mud Weight}}{\text{Original Mud Weight}}$ = $\underline{\hspace{2cm}} \text{ psi} \times \frac{\underline{\hspace{2cm}} \text{ ppg}}{\underline{\hspace{2cm}} \text{ ppg}}$
 = $\underline{\hspace{2cm}} \text{ psi}$
- (9) Circulating Time To Bit = $\frac{\text{Drill Pipe Capacity} \times \text{Drill String Length}}{\text{Kill Rate}} = \frac{\underline{\hspace{2cm}} \text{ bbl/ft} \times \underline{\hspace{2cm}} \text{ ft}}{\underline{\hspace{2cm}} \text{ bpm}} = \underline{\hspace{2cm}} \text{ min}$
- (10) Strokes = Kill Rate x Time = $\underline{\hspace{2cm}} \text{ stks/min} \times \underline{\hspace{2cm}} \text{ min} = \underline{\hspace{2cm}} \text{ strokes}$

- * Omit if only surface casing set or mud near fracture gradient
- Use 0.5 ppg for Trip Margin if hole less than 7 in. diameter

DRILL PIPE PRESSURE SCHEDULE

III. WELL-CONTROL EQUIPMENT

INTRODUCTION

This is a discussion of the applicability and limitations of available well-control equipment to the special problems of geopressured drilling.

A somewhat broad viewpoint of what constitutes well-control equipment is used in this report. Like many other subjects, it is difficult to describe the exact limits of what well-control equipment is. If any error is made, it is on the broad inclusive side.

SUMMARY OF EQUIPMENT

Blowout Preventer Stack

The basic well-control equipment is the BOP stack. It may consist of two sets of pipe rams, a set of blind rams, and an annular preventer. The rams are normally available in working pressures up to 10,000 psi, or as high as 15,000 psi on special orders. The annular preventers are normally rated with working pressures up to 5,000 psi; but 10,000 psi equipment is becoming available.

Based on oil and gas drilling experience, the steel, structure, and design of the entire stack appear to be adequate for any geopressure work now contemplated. The design of 15KSI stacks is a difficult state-of-the-art project, but manufacturers are fulfilling this requirement.

The only foreseeable problems are with seals in the BOP's, the annular preventer packer which is an elastomer bonded to steel stiffeners, and seals within the annular BOP. This problem has been extensively reported in the past as an elastomer high-temperature problem. With the BOP stack, it is unlikely that the stack will get hot enough to do major harm to the seals. The annular preventer packer may have to be water cooled in some cases until better high temperature elastomers are available.

If attention is given to the temperature problems with seals, heat expansion, sizing, and high-pressures, the surface BOP stack should be satisfactory for geopressure drilling.

Choke Manifold

When designed for 15KSI, the chokes and choke manifold are adequate for normal geopressure operations. The basic limitation is there is no standard manifold. API RP 53 recommends some alternative designs but land rigs often do not meet these recommendations. Requirements need to be established for rigs involved in geopressure drilling. It would also be helpful to establish a standard design of manifolds so errors or undesirable design features can be eliminated with experience.

Wellheads

Wellheads to 20KSI for completed wells are available on special order, although 15 KSI should normally suffice.

Gas Separators

Since it can now be assumed that geopressure wells will produce large amounts of gas with salt water, provision should be made for mud-gas separators of adequate volume to remove the gas to a flare stack. This equipment is available, but not universally used. Free gas separators, generally referred to as "poor-boy separators," are used on a kick to remove the free gas from the choke discharge lines. They are often indeed "poor-boy separators" and probably need improvement. The larger gas separators used in West Texas and Oklahoma are effective and well proven.

After separation of drill gas from drilling fluid, entrained gas must be removed. Several adequate degassers are available commercially for doing this. The vacuum-type degasser that pumps gas to the flare line is safest of the gas separator systems since it removes gas from the pit area.

Detection Equipment

A major effort should be made to provide better and more accurate flow-line flow indicators and pit-volume indicators. The equipment now available is theoretically adequate, but in practice leaves much-to-be-desired in reliability and accuracy.

Manufacturers are capable of improving this equipment, but lack the incentive since there are no standards to work against. With good accurate flow sensors and pit-volume measurement, the severity of kicks could be limited to the point of reducing blowouts to almost a zero level.

**BLOWOUT PREVENTER STACK
(For High-Pressure Well)**

Figure III-1.

1. Annular preventer.
2. Double ram set.
3. Spool with side outlets and valves for choke and kill lines.
4. Single ram.
5. Wellhead flange clamp.
6. Hydraulic closing lines.
7. Manual ram locks.

Courtesy Cameron Iron Works

Annular Preventer

The annular preventer closes the annulus on drill pipe, drill collars, tool joints, or wire line. Generally, the annular preventer is closed first when a well kick threatens so the driller does not have to worry about the position of the tool joints and so the pipe can be moved to avoid sticking. The annular preventer is also used to strip pipe in or out of the hole.

The annular preventer can be closed on the kelly, tool joints, drill collars, casing, or wire line. It can also close over the open hole, but this is not recommended because of the distortion of the packer.

The annular preventer is closed by hydraulic pressure on the closing piston. The "rubber" packer element is squeezed closed around the pipe. Annular preventers are usually closed with about 800 psi pressure. The time that it takes to close depends on how long it takes to flow enough hydraulic fluid through the lines to operate the piston. The volume required to close varies from 10 gallons to 100 gallons depending on the annular preventer type and size, as well as the control system.

Since the packer element of the annular preventer is very thick it suffers from high temperature hardening. In high-temperature geopressure drilling, it is possible for the mud temperatures to get high enough to cause failure of the annular packer although it would take a "worst-case" set of circumstances.

The way the annular preventer is used, the cooling effects of the mud system, and gas expansion all indicate that generally the annular packer should be adequate.

The other elements of the annular preventer system--the seals, the hydraulic fluid, clearances, and the use of small accumulators for stripping purposes--also appear to be adequate for the immediate future.

Whether the whole system of the annular preventer is properly tuned for high-temperature geopressure work is not clear. While the individual elements appear satisfactory, some attempt might be made to analyze the annular preventer as both a stand-alone system and as part of the entire BOP stack system.

HYDRIL ANNULAR PREVENTER TYPE GK

Cutaway view of GK BOP with packing unit fully open. The Hydril GK opens to full bore to allow passage of large-diameter tools through open bore as well as maximum annulus flow of drilling fluids. Packing unit returns to full open position due to normal resiliency of rubber packing unit. Retention of opening chamber pressure will ensure positive control of piston and reduce wear caused by vibration.

Cutaway view of GK BOP with packing unit closed on drill pipe. The packing unit seals off on tool joint, any size pipe, casing, or wireline to rated pressure.

Cutaway view of GK BOP with packing unit closed on square kelly. The packing unit seals off on square or hexagonal kellys to rated pressure.

Cutaway view of GK BOP with packing unit closed on open hole. Complete closure of packing unit safely holds well pressure, without leakage, equal to the rated working pressure of the preventer.

Figure 111-2.

Courtesy Hydril

SHAFFER SPHERICAL ANNULAR PREVENTER

During stripping in, well pressure and pipe movement oppose each other. Well pressure compresses the rubber portion of the element against the steel segments as the tool joint moves down into the Spherical.

During stripping out, well pressure and pipe movement are in the same direction. Rubber is compressed firmly against the steel segments at the top of the element, but rubber at the bottom is only slightly compressed. This creates a "funnel effect" that makes it easy for a tool joint to pass through the sealing element.

At complete shutoff, the steel segments provide ample support for the top portion of the rubber. This prevents the rubber from flowing or extruding when confining high well pressure.

Figure 111-3.

Courtesy N. L. Shaffer

Ram-Type Blowout Preventers

Ram-type blowout preventers seal off the annulus of the well or the open hole. Ram-type preventers seal only against the size pipe or open hole for which they are sized. The ram block is steel with only a small packer to seal at the face of the mating blocks and around the pipe. This provides a strong, reliable, and safe "valve" for closing off the wellbore.

A typical set of ram preventers consists of a "blind" ram to close on the open hole and a pipe ram sized to fit the drill pipe in use. As well pressures become higher and rigs larger, more rams are added to the stack. Two-pipe rams and a blind ram are not an unusual stack arrangement for drilling where higher-than-normal pressures are expected. This allows one of the pipe rams to be changed to fit the casing size when casing is run.

In general, when pipe rams are used, the pipe is not rotated or reciprocated. While rams were not designed for pipe movement, the pipe can be moved through the rams quite extensively without damaging the packer elements. A stripping technique using pipe rams is quite common.

Pipe rams should be operated hydraulically rather than manually because manual operation is slow and can become hazardous to both the man under the floor closing the rams and the crew on the floor waiting for ram closure. They can be locked closed either manually or hydraulically.

Pipe rams are well suited for their task in geopressure work. The sealing rings can be provided of Viton material which resists temperature. The ram sealing area is small and the distortion of the packer area is minimal; therefore problems with the sealing packer element are significantly less than with the annular preventer.

Some care should be taken with the specifications of the ram system for geothermal work. The temperature limits of 700°F for "worst-case" analysis are well beyond the normal temperature limitations. Probably the pipe rams and blind rams can be effectively modified for the most severe geothermal conditions yet experienced, but a testing program to check the actual operation of rams under extreme temperature conditions might be prudent.

The rams for geopressure drilling fall well within the experience of the manufacturers and should pose no major problems that are not already being closely monitored.

CAMERON RAM PREVENTER
TYPE "U" SINGLE PREVENTER

Figure III-4.

Courtesy Cameron Iron Works

SHAFFER RAM PREVENTER
TYPE SL TRIPLE PREVENTER

Figure III-5.

All ram manufacturers make at least double units to save space. In the above unit, notice that the upper ram is a shear ram for cutting the pipe as well as sealing the open hole. The open bonnet in the center is a good view of the ram packing that would be subject to high well temperatures. Side outlets in the front of the picture are provided for pumping into the well under pressure.

Courtesy N. L. Shaffer

Drill Pipe Safety Valves and Kelly Cocks

Drill pipe safety valves and kelly cocks are full opening ball or plug valves used to stop flowback up the drill string if a well kick should occur.

The drill pipe safety valve is usually stored on the floor in a sub that is equipped with handles for quick installation on the drill pipe. The drill pipe safety valve is used to stop flowback up the drill pipe when the kelly is disconnected.

The lower kelly cock is the same type of valve installed in a sub on the bottom of the kelly; it is used for two reasons:

- to stop flow-up into the kelly so it can be disconnected, or
- to shut off the kelly to relieve pressure on the kelly, hole, and swivel.

The upper kelly cock is on the top of the kelly and is used as a secondary valve for relieving pressure on the kelly, hole, and swivel.

These valves would not normally be subjected to extreme pressure or temperature. However, since they are designed as emergency equipment, they should be able to withstand a "worst-case" situation.

The valves should be checked for high-temperature clearances, greases, and sealing rings. The pressure capability

of these valves is very good, but not all of the manufacturers have prepared for the high temperatures that may be found in geopressure drilling.

DRILL PIPE SAFETY VALVE "TIW" VALVE

Figure III-6.

Courtesy Texas Iron Works

Drill Pipe Inside BOP

The inside BOP is used like a safety valve to shut the drill string off so it will not flow; but it also allows pumping through the drill string. This is needed when running drill pipe back in the hole either under pressure or when a kick has occurred.

The inside BOP takes several forms. It may simply be a float in the drill string. This is generally called a "float" rather than an inside BOP.

What is normally referred to as an "inside BOP" is the dart-type or ball-type sub that is stored on the floor. It makes up on the top of the drill string and usually has some makeup handles on the top for easy handling. The sub is locked in the full open position on the floor by a pin or sleeve so mud can backflow up the pipe while it is being made up. (It could not be made up against pressure otherwise.) After the pipe is made up tight, the pin or sleeve is removed and upward flow of the mud shuts the valve.

A third kind of inside BOP is the drop-in, or pump-down, tool. It is used when pipe is to be stripped from the hole under pressure or with wire line tubing operations. This tool requires a sub in the drill string, usually placed near the bit. The sub has a ring groove in which the element locks.

These tools need the addition of high-temperature O rings and seals to be compatible with geopressured drilling. In geopressured drilling, care must be taken that the valve has a high enough pressure rating to be compatible with the contemplated pressures.

INSIDE BOP

Figure III-7.
Inside BOP for
drill string shutoff,
but allows pumping
down.

Courtesy Gray Tool

Drop-in Inside BOP
Drops down or pumps down
the drill pipe to a sub
located at the bit to
shut off flow in the
drill string

Figure III-8.
Courtesy Hydril

FLOAT VALVES

PISTON TYPE FLOAT VALVE
Fits in drill string near
bit to prevent backflow
in drill bit.

FLAPPER TYPE FLOAT VALVE
Full opening valve used
in drill string near bit
to prevent backflow.

Figure 111-9.

Courtesy Baker

Accumulator System

The accumulator (or closing unit) system provides quick closing power for the BOP stack. The accumulator has a stored supply of hydraulic fluid under pressure which can shut the pipe rams in six seconds or less on some surface mounted BOP stacks.

To operate the accumulator, it is only necessary to push the control lever for the desired BOP to the close position.

Accumulator systems normally consist of a number of bottles of fluid pressurized to 3,000 psi. The fluid sent to the annular preventer goes through a regulator where it is regulated down to 700 to 1,000 psi and then sent to the annular preventer. The fluid that flows to the pipe rams goes from the bottles to a separate regulator where it is regulated to 1,500 psi and then sent to the rams. As the bottles are being discharged, a pressure controlled switch starts a pump that recharges the bottles so the pressure in the bottles stays near 3,000 psi.

The accumulator system is a 'must' for geopressure drilling. It allows rapid closing in of the well, and equally important, it allows remote operation of the BOP stack.

Accumulator System

Koomey S Series
Accumulator/Pump
Unit Model T20160-3S/AC62
and Manifold Model SU2KB7S

Figure III-10.

1. Air Supply Inlet
4. On-off Pressure Switch
6. Air Operated Hydraulic Pumps
8. Suction Strainer
10. Triplex Pump
11. Triplex On-off Switch
12. Motor Starter
17. Accumulators
22. Four Way Valves
23. Bypass Valve

Courtesy Koomey

Choke Manifolds

The choke and kill manifold directs mud to the proper choke during a well kick. It allows alternate paths in case a valve or choke washes out, or it allows flow directly to a separator or bypass line. It also provides a method of controlling pressures at the surface so the well can be tested or rig repairs can be effected.

Manifolds tend to be an overlooked piece of equipment, and somewhat of an afterthought especially in geopressure drilling. The manifold needs to be designed for the pressures, flow rates, and functions that need to be accomplished. While there are some suggestions on this subject in API RP 53, there is very little information concerning standard design or design criteria.

The best of the manifold systems for geopressure drilling are the direct transfers from oil and gas drilling. Depending on the test program while drilling, manifolds may or may not be suitable for geopressure work. They may lack adequate diameters for high-volume testing or they may lack high enough pressure rating. It is quite probable that the valving and tubular expansion problems for high temperature have not been considered. The problem of high temperature seizing of plug and ball valves and of stem packing on gate valves needs to be examined at some length.

Geopressure manifolds should not be equipped with conventional adjustable chokes since they have a tendency to seize at high temperatures.

The whole subject of the choke manifold for geopressure drilling should be re-examined and the purpose and specifications for the manifold should be redefined.

RP 53: Blowout Prevention Equipment Systems

**TYPICAL CHOKE MANIFOLD ASSEMBLY FOR 10M AND 15M
RATED WORKING PRESSURE SERVICE — SURFACE IN-
STALLATION**

Figure III-11.

CHOKE AND KILL MANIFOLD

Figure III-12.

Courtesy Cameron Iron Works

Adjustable Chokes

The adjustable choke provides the easiest and most accurate way of controlling a well kick. SWACO and Cameron have the most commonly-used remote operating chokes designed specially for well killing and they are completely different designs. The remote operating panel provides a control center for well killing operations that is a valuable addition to the choke. The adjustable choke and remote operating panel are an important part of modern well-control operations.

There is limited data on adjustable choke operation above 300°F. It appears that either the SWACO or Cameron choke can be equipped with Viton seals and probably operate in the 500°F range. The chokes used for geopressure work should be equipped for high temperature and records should be kept of any use in extreme temperatures. It is difficult to duplicate the extreme pressure and temperature conditions under which the chokes would have to operate without creating extremely hazardous test conditions.

Courtesy Cameron Iron Works

Figure III-13.

Adjustable Choke

Courtesy Cameron Iron Works

Figure III-14.

The conventional adjustable choke is part of all choke manifolds and is extensively used in production and some drilling choke operations. For well-control procedures, it gives poor service because early failure due to erosion or chipping in the needle area occurs. For extended high-temperature work, the conventional choke is further limited because it tends to seize when heated. Conventional chokes should not be used in geopressure manifolds until they have been proved operational under the temperatures that may be encountered.

SWACO Super Choke

The Super Choke (Figure III-15) is a 10,000 psi (700 Kg/cm²) valve that operates by rotating one plate against another. The plates each have a "half moon" opening and as the openings rotate into line, the choke opens. The tungsten carbide plates slide against each other on a lapped surface so that the power used to rotate the plate is much less than the well pressure. It is a very efficient high-temperature choke, because the sliding plates are not temperature sensitive.

The choke plates are 1" thick and 3-1/4" in diameter. In full open position, the opening is equivalent to a 1-5/8" choke bean.

Cameron AX Choke

The Cameron AX Choke (Figure III-16) is a 5,000-psi or 10,000-psi choke. It uses a bar that moves in and out of a tapered choke gate. The movement is controlled by a double-acting hydraulic cylinder. The choking action is produced as the bar approaches and then enters the tapered seat. Clearances between the bar and seat in the choke are not critical, so it is an effective high-temperature choke.

Full open is equal to a 2" choke bean. The wear areas of the bar and seat are tungsten carbide.

SWACO SUPER CHOKE
Drilling Choke

Choke Console

Choke

Choke Cutaway

Figure III-15.

CAMERON AX DRILLING CHOKE

Choke Console

Choke Gate
Choke Seat

Choke

Mud Gas Separators

The drilling separator system is down stream of the manifold and choke; it separates gas from the drilling fluid. In oil well drilling, and geopressure drilling, the form of the separator depends upon the quantity of gas expected. A large float-operated tank is used where large quantities of gas are expected. The tank is slightly pressured by the gas and is able to send the gas to a remote flare. This system is used mostly in West Texas and western Oklahoma where large quantities of gas are produced while drilling with very light muds, or where sour gas is produced.

For conditions where little gas is expected, the "poor boy" separator is used. In its simplest form, it is a piece of casing used to absorb some of the velocity of the mud from the choke and let the gas rise and the mud run off to the mud pits.

Often the "poor boy" separators are not of adequate design allowing discharge of quantities of mud through the gas line and slugs of free gas to the shale shaker.

MUD GAS SEPARATOR

1. Mud and Gas from Manifold.
2. Float Valve for Fluid Level Control.
3. Gas Line - out.
4. Mud - out.

Courtesy SWACO

"POOR BOY" GAS SEPARATOR

Degassers

There are a number of degasser designs that will effectively remove gas from the drilling mud. For geopressure drilling operations, degassers that use a vacuum pump to move the gas to a remote location or to the flare line are necessary. Degassers not using a vacuum pump remove the gas from the mud, but leave it in the pit area, thus providing a hazard.

Vacuum Pump Degasser

Courtesy SWACO

Courtesy Wellco
Figure III-18.

Mud Pit-Level Indicators

The pit-level indicator presently used adds the volume in each pit and reports, on a recorder and an indicator, the total pit volume or a working pit level.

The pit-volume indicator is a basic well-control warning instrument. A well kick pushes mud out of the hole; this is recorded by the pit-level indicator as an increase in pit level or pit volume. So one of the warning signs of a well kick is an increase in pit volume. The driller's indicator has an alarm system that calls attention to pit changes.

Pit volume systems operate simply. The height of the mud in each pit is measured. This height is then multiplied by the pit volume (in barrels per inch or a similar measurement). The output of all the pits is then added together and reported on the chart and indicator. These measurements and calculations may be done either electrically or pneumatically (by air).

On most pit-level indicators, the gain or loss of mud is indicated, and alarms are provided to show gains or losses exceeding preset limits.

The mud-pit totalizer systems lack reliability. Such systems are especially erratic in very hot muds. As with the flow sensing systems, the accuracy is adequate; however, when subjected to heat and steam, the systems are not reliable enough.

MUD VOLUME TOTALIZER

Figure III-19.

Courtesy Martin Decker

Mud-Return Indicator (Flow Line Sensor)

The mud-return indicator is usually a level indicator in the flow line. This may appear inaccurate, but it is a wier, and wiers are one of the oldest methods of measuring flow. The level indicator in the flow line reports the height of mud in the flow line. This signal is sent to the drillers console where it is reported as "percent of flow" or "gpm." Neither of these numbers is as important as a change in flow.

If a well kick occurs, something has entered the wellbore. Whatever enters will push mud out of the flow line and will be shown as an increase in flow. So an increase in flow is the first sign of a kick, and the flow sensor is the first indicator of a kick.

The flow line sensor is one of the weak links in the detection system for well kicks. Although inexpensive, these systems are not reliable. Since the flow sensor is the first indication of a well kick, these systems need improved reliability. Flow sensor systems are a 'must' in geopressured drilling. Unfortunately, they are only barely adequate in their present configuration.

Figure III-20.

Trip Measurements (Hole Fill-Up)

A basic safety measure is to fill the hole with mud as the pipe is pulled during a trip. If the hole is not filled to allow for drill pipe displacement when the pipe is withdrawn, the bottom-hole pressure is reduced and the well may kick. There are two basic measurement devices used to measure hole fill-up and the companion hole displacement when returning the drill pipe to bottom:

- the pump stroke counter and flow sensor and
- the fill-up tank.

The pump stroke counter and flow sensor combination is the most common fill-up measurement device. During a trip, after a fixed number of stands of pipe is pulled, the pump is turned on at an idle speed. The pump stroke counter counts the pump strokes and when the hole fills up and mud flows down the flow line, the flow sensor turns off the pump stroke count. The count of pump strokes is a reasonably accurate method of determining volume of mud in the hole for a certain amount of drill pipe pulled. Often, cumulative pump strokes are retained for a more accurate overall look at fill-up. When going back in the hole, the flow sensor indicates that the pipe is displacing mud out of the hole and that the displacement stops between stands of pipe.

The pump stroke counter and flow sensor are adequate for most normal circumstances and, if carefully used and carefully maintained, they are accurate enough to prevent anything more than the smallest of kicks. However, the basic flow sensor assembly suffers from a lack of reliability as is discussed under the topic heading on page III-34.

The most accurate measurements of hole fill-up and displacement are with the trip tank. The trip tank is a small tank from which accurate measurements of the mud pumped into the hole can be made. The best trip tank arrangements continuously circulate over the open hole to keep the hole full. The measure of mud displaced versus the pipe pulled or run-back into the hole is displayed on the floor in front of the driller.

Either the pump stroke counter and flow sensor or the trip tank can be used for geopressure drilling. In both cases, the problem is one of reliability combined with an obvious and accurate floor readout. Although technology is adequate for current purpose; reliability and maintenance are serious problems.

TYPICAL FILLUP TANK

Figure III-21.

PUMP STROKE/RATE COUNTER
Figure III-22.

Courtesy Geolograph

Gas Detectors

Gas detectors on a rig have two general uses. The mud logger uses a gas detector to detect gas in the mud. Gas in the mud line may indicate that the rig is drilling a gas-bearing formation or that gas is feeding into the mud under pressure. If the gas at each connection--when it is circulated up to the surface--is much greater than when drilling, this is a sign that pressurized gas is entering the mud and perhaps the mud weight should be increased.

The area gas detectors on the rig are used to warn of gas concentration in places where an explosion or fire could occur.

Most of the new gas detectors use a catalytic burner to detect the presence of burnable gas. The catalytic element "burns" the gas and the resulting heat changes the ability of a wire to conduct electric current. This change in current operates the alarm and recording system.

Gas detection for geopressure drilling has been extensively developed for the oil and gas drilling industry and the technological transfer is straightforward.

Automatic Recording Gas Detector

Figure III-23.

Courtesy NL Baroid

IV. RESPONSIBILITIES AND TRAINING FOR DRILLING SUPERVISORY AND OPERATING PERSONNEL

The defining of job responsibilities and formal training are not a strong tradition in U.S. industry, and drilling people are no exception. The economics of failure and its natural selection process tended to weed out those who could not learn rapidly enough to successfully fill a new position. Successful field practices developed through time and experience. The resolution of most of the problems and the practices required were generally well known, at least in the areas where problems existed.

In general, the States have accepted this attitude and state laws tend to be related more to land use and to Workman's Compensation (safety) problems than to such specific problems as well control. There are exceptions: New Mexico requires mud pit volume measuring equipment; California has well-control regulations, and casing requirements are mentioned by almost all states. So with some exceptions, the basic well-control or blowout control laws have been written and administered by the Conservation Division of USGS under the provisions of The Outer Continental Shelf Lands Act.

There are 5 applicable standards or laws that deal with blowout control (see Appendix). They are:

- (1) USGS OCS Order Number 2;
- (2) State of California Oil and Gas Regulations;
- (3) API T-3;
- (4) GSS-OCS-T 1;
- (5) API RP 53

Training

Well-control training is well established for offshore continental-shelf wells as a result of the USGS Order #2. Preceding that, oil company and service company concerns had established formal schools and seminars as early as 1969. At present, the USGS-T 1 has formalized the school curriculum standards and there are a number of private and public schools in operation in the U.S. Figure IV-1 from the January 1978, Oil and Gas Journal lists U.S. schools and students.

International training is somewhat less concentrated and more in the hands of private operations, so it is more difficult to check on the actual operation of the schools. Figure IV-2 lists information available on international training.

Nationally and Internationally, most of the major oil companies and contractors have training schools for well control. These tend to be traveling schools that take the training to the operation or drilling rig. Figure IV-3 lists information available on these schools.

The three figures shown probably do not represent all the training available. There is a great deal of well-control training that is difficult to trace because it is not formally documented. It should be noted, however, that almost all of this training deals with geopressed operations and the majority of it has to do with offshore or marine operations.

U.S. offshore oil industry may face training crunch

A TRAINING crunch may be in store for the U.S. offshore petroleum industry as new employees and present drilling crews needing government certification line up at the classroom door.

New U.S. Geological Survey certification requirements for drilling operators and contractors working in federal waters pose two immediate problems to well-control trainers.

First, their courses must be certified before USGS will certify their graduates. Second, the new requirements will send many graduates now at work back to school.

So training programs, both company in-house courses and independent industry schools, are beginning to prepare for the USGS test and increased student loads.

Several schools are expected to apply for certification this month.

Student load. At least 5,000 persons working in U.S. federal waters will require the new certification. The number could be as high as 10,000, depending on individual company manning requirements and changeout policies.

During the next 23 months, industry will have to train 8,000 new students. And another 8,000 students will require refresher training. But requirements will be heavier than that because those figures assume zero turnover and diversions of all training for land contractors to the offshore market.

Industry's training capacity at present is about 12,000 students/year for all types of courses. Half of that training is provided by oil companies and contractors and the other half by industry schools led by colleges and drilling-mud companies.

Most popular schools appear to be those cosponsored by the International Association of Drilling Con-

Major schools*

Company	Total students trained	Stated capacity, (Students/year)	Cost (\$/man)
LSU	3,931	960	400
U. of Oklahoma	1,200	800	400
IMCO Services	7,000	1,100	Free
Dresser Magcobar	400	250	400
NL Baroid	200	500	300
Milchem	900	500	Free
Simtran	2,000	1,000	350+
International Training	New		
WOGA (Ventura College)	New	480+	
Prentice & Records (USL)	2,000	1,000+	385
Oil & Gas Institute	New	500	400
Petex	750	500	400
Total	18,381	7,590	

*Subject matter and duration vary.

tractors (OGJ, Sept. 19, 1977, p. 147). IADC-cosponsored schools that have trained more than 5,000 students include Louisiana State University, Baton Rouge; University of Oklahoma Norman; University of Southern Louisiana, Lafayette; and Lamar Tech, Beaumont, Tex.

Other colleges are setting up schools, and many existing schools are expanding. Still, industry trainers say a student training crunch could come just before the USGS regulations take effect.

Adding to the training-demand surge are the cumulative requirements of USGS certification. For example, a tool pusher who wants to continue work as a tool pusher

after the regulation deadline must return to school and complete approved courses for rotary helpers, derrickmen, and drillers, as well as a course for tool pushers.

Industry effects. Even land-drilling contractors may feel the squeeze, as training capacity in non-OCS-related courses is shifted toward fulfilling the new USGS requirements and handling the student load.

Moreover, training will be increasingly expensive as schools strive to insure their students meet the USGS demands. That means contractors will have to exert closer control on turnover rates since they will have more money invested in each worker.

And if a training logjam does develop, contractors who start late in beefing up their training programs may find themselves short-handed.

School response. Spokesmen for several schools planning to expand their courses say they are worried whether there will be enough qualified instructors to handle the bigger programs. Time, paperwork, and investment requirements are heavier under the USGS rules, too.

And course developers are uncertain about some certification procedures. They don't yet know whether USGS will require written examinations. If so, some courses will have to add a day to their training times, reducing capacities.

Only one school, Prentice & Records, has applied for USGS certification.

The company says its application is modeled after that of a surface-safety school at the University of Southern Louisiana already approved by USGS.

Other schools say they are still studying the final standards and deciding how to handle paperwork.

<u>Company</u>	<u>School Location(s)</u>
Exxon	Humble (Texas) King Ranch (Texas) As Required
Gulf	Houston, As Required
Shell	White Castle (Louisiana) As Required
Pan American Petroleum	As Required
Amoco	As Required
SEDCO	Rig Site
Loffland Bros.	Rig Site
Reading and Bates	Lafayette (Louisiana)
Chevron Oil	New Orleans (Louisiana)

Figure IV-3. PRIVATE U.S. BASED TRAINING SCHOOLS FOR WELL CONTROL
(Private schools that are operated on a formal scheduled basis.
Many more are operated on a less formal basis.)

<u>School Operator</u>	<u>Operated For</u>	<u>Location</u>
Petroleum Industry Training School	Canadian Industry	Edmonton, Canada
Payjak Land and Marine	Private	As Needed, Canada
Scottish Offshore Training Association	British Petroleum Training Board	Aberdeen (Montrose) Scotland
SNEAP	SNEAP	Pau, France
OSCO	Iranian Government	Awaz, Iran
Simtran	Zapata Drilling Company	Rotterdam, Netherlands
Reading and Bates	Reading and Bates	Malta
Shell International	Shell International	The Hague, Netherlands
Simtran	Private	As Needed, International

Figure IV-2. INTERNATIONAL WELL-CONTROL TRAINING SCHOOLS

Geopressured Wells

In land drilling of geopressured wells, State, BLM, and Forest Service procedures are most common. These are mostly related to land use, safety and environmental protection. Specific regulations covering well control tend to be by inference and for occasional specific pieces of equipment and techniques. (i.e. The hole will be kept full. Pit-volume measuring systems will be used.) The major thrust toward well-control regulation has come in "The Notices to Leases and Operators of Federal Oil and Gas Leases in the Outer Continental Shelf." These regulations for the various areas (Alaska, the Pacific Coast, the Gulf of Mexico and the East Coast) have spelled out operating procedures in a very specific manner. In these orders, Order #2 covers the drilling procedures. A new general order to cover procedures for the entire Continental Shelf area of the United States is being prepared.

The Operating Orders may be modified by specific Field Operating Orders. These may cause the general orders to be modified for the specific conditions of a field, but these modifications would not in general affect this discussion.

The Order for the Gulf Coast, which is the most detailed of the Orders concerning well control, requires that "company and drilling contractor supervisory personnel shall be trained in and knowledgeable of present-day well control."

As a further continuation of their efforts, the USGS has issued GSS-OCS-T 1 "Outer Continental Shelf Standard Training and Qualifications of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations." The regulation was based on The API RP T-3 "Training and Qualification of Personnel in Well-Control Equipment and Techniques for Drilling on Offshore Locations."

Geopressured Wells - General Practice

Since geopressured drilling in the Outer Continental Shelf area is covered by USGS rules, drilling practices and training requirements closely follow the rulings with additional safety practices and drills specified by the operator and contractor. The general practice is that equipment is tested daily or weekly as the case might be, drills are held tourly, and all drilling personnel have received formal training in well control for the position that they hold.

In areas not covered by the USGS Regulations, operators and contractors have tended to follow the offshore regulations with modifications suitable for their area. In those areas, drilling supervisors usually attend the same schools on well control as personnel subject to USGS Regulations. The testing procedures and drills are often modified for the specific problems of the area. In the area covered by state regulations, the operator and contractor generally use the following practices:

1. Supervisory personnel have attended a well-control school;
2. There is a standard procedure or plan for well control for the rig and it is most generally part of the drilling program;
3. The BOP stack, manifold and casing are pressure tested before drilling out from under each string of casing;
4. The BOP stack is function tested each day or at least weekly;
5. Periodic well kick detection drills are held;
6. Either a flow sensor-pump stroke counter or a trip tank is used to monitor fillup on trips.

A record of these tests and drills is usually kept in the IADC Drilling Report Book.

These procedures and drills vary from operation to operation with high-pressure wells drilled by major operators and large contractors following the procedures listed above very closely. Small operators drilling into more normal pressure formations tend to be less exact in their operations.

Improvements to Field Practices

Geopressure drilling has the potential of being so hazardous that it is difficult to decide where the limits of good practice end, and hazards are being increased by extreme caution.

When drilling geopressured wells, it would appear to be worthwhile to follow the strict rules set out by the USGS for Operations (OCS Order #2) for Gulf Coast drilling, Training (GSS-OCS-T 1) and Drills (both of above). The above orders are well organized, use the best state-of-the-art information for geopressure drilling, and provide the most reasonable safety margin for operations. Geopressure wells will be experimental and are "wildcats" within the definition of entering unknown zones. It seems that any attempt to develop general land operating practices would simply be duplication of the provisions worked out at such effort by the USGS and proven by time and experience.

As previously mentioned in this report, the mud logging services provide the only pressure and well kick prediction service available. The prediction techniques are well documented and reliable, but there is no rig floor equipment that is designed to provide this data. The mud logging services use a combination of computer analysis and hand calculation to predict

formation pressures and required mud weights. Data Collection (mud logging) services should be used to monitor formation pressure from drilling data to fill the information gap on the prediction of pressures and the logger on duty should monitor the fill-up and displacement on trips.

V. ECONOMIC CONSIDERATIONS RELATED TO WELL CONTROL

Blowouts are the spectacular manifestations of loss of control over subsurface fluids. In this study, only blowouts and kicks while in the process of drilling the well have been considered. (However, it should be noted that the majority of loss-of-control incidents occur during the workover or production life of a well.) Kicks or blowouts that occur during the drilling process are about evenly divided between tripping and drilling.

The immediate problem of a well kick or blowout always overshadows the longer-term economic problems:

1. Loss of life on the rig;
2. Loss of equipment on the rig;
3. Danger to life in the area;
4. Ecological damage;
5. Unfavorable political reaction;
6. Movement or purchase of equipment for controlling the well;
7. Movement of personnel for controlling the well.

However, the hazards accompanying a blowout or well kick finally are economic considerations.

But all well kicks or blowouts are not major disasters. The loss of control of a subsurface fluid may cost only a few hours of rig time. The well-control incidents might be broken down into the following categories and scenarios.

A. Minor Well Kicks

When the well kicks and the flow of formation fluid into the wellbore is somewhat less than 50 bbls, the kick is controlled by simple standard procedures. This is a quite common occurrence. The data are not available to document the frequency of occurrence, but as an estimate this will occur at least once a year on half of the rigs drilling in the U.S. (approximately 1,000 occurrences).

The cost of a minor well kick is about three circulations of the mud system or 12 hours of rig time.

$$12 \text{ hours} \times \$100/\text{hr} \times 1,000 \text{ incidents} = \$1.2 \times 10^6$$

B. Major Well Kicks

After the well kicks, there is difficulty controlling the well due to lost circulation and hole problems. The drill pipe is stuck and the bottom of the hole collapses. This occurs less often than a minor kick, but no documentation of the frequency of occurrence is available. It might be assumed that this occurs only one-quarter as often as the minor well kick.

The estimated loss on a major well kick is:

Rig Time 14 days x \$1,200	\$ 17,000
Drilling Mud	75,000
Drill Pipe & Drill Collars	20,000
Fishing Services and Special Tools	10,000
Cementing Services	10,000
Intangible	<u>10,000</u>
Total	\$ 142,000

$$\$142,000 \times 250 \text{ incidents} = \$35.5 \times 10^6$$

C. Blowout, Minor

The well blows out as a result of some problems during a major well kick. No one is hurt and the rig is moved off the well successfully. The hole bridges and kills the blowout, but part of the hole must be redrilled. The USGS lists five incidents of this nature in the Gulf of Mexico in 1976 and five in 1977. This is the most hazardous area so it would not be proper to proportion the incidents directly. In January of 1976, there were 1800 drilling rigs working in the U.S.; 132 of these were in offshore (but not necessarily OCS) water. This is a 4% incident rate. Assuming a 2% incident rate for the U.S...

$$2\% \times 2,000 = 40 \text{ incidents.}$$

The costs would involve the loss of part of the hole plus the cost of redrilling the well. The cost of lost production will be ignored.

Rig Time 30 days x 1,200	\$ 36,000
Redrilling Costs 30 days @ 12,000	36,000
Mud Cost	100,000
Cementing Services	50,000
Intangible Costs	<u>100,000</u>
	\$322,000

$$\$322,000 \times 40 \text{ incidents} = \$12.8 \times 10^6$$

D. Blowout, Major

The drilling rig is destroyed and there may be loss of life or damage to the location due to fire and cratering. The presence of H_2S gas would be a significant problem, but there is little evidence that this will happen in Gulf Coast geopressure wells.

USGS lists one such event in 1977, one in 1976, and one in 1975. Based on one event for 132 rigs in the Gulf, the percentage rate is 0.75%. Using the logic that the Gulf is twice as hazardous as the U.S. as a whole, .375% of 2,000 rigs is 7.5 events.

Rig Loss	\$1,500,000
Redrill Hole	700,000
Fire Fighting or Directional Cost	700,000
Cementing Services	100,000
Intangible Costs	<u>150,000</u>
	\$3,150,000

$$7.5 \text{ Events} \times \$3 \times 10^6 = \$22.5 \times 10^6$$

OR

The rule of thumb is often heard quoted as 5 times well cost or \$3,500,000. With 7.5 events...

$$\text{Costs} = \$26 \times 10^6.$$

As an estimate then, the cost of well kicks and blowouts in hydrocarbon drilling approaches $\$60 \times 10^6/\text{year}$. What percentage of this reflects geopressured conditions is hard to ascertain, but certainly the majority of the cost would be attributed to the more expensive geopressured drilling.

In Alberta, Canada, there were 153 blowouts between 1948 and 1977. This is an average of five blowouts per year. If the Canadian rig average of 200 rigs in 1976 were compared to the U.S. average of 2,000, there should have been fifty blowouts per year in the U.S. The data appear to tie very closely. The frequency of blowouts appears to have been about 2% of the drilling rigs per year.

VI. RECOMMENDATIONS

The oil and gas drilling industry has made a major effort to reduce the hazards of drilling high-pressure formations. The API Recommended Practices and the U.S.G.S. operating regulations cover most of the problems in an adequate manner. There are, however, several areas that need some improvement. This is due to the particular problems encountered in drilling geopressured wells.

While it is not possible to have absolutely safe and assured drilling of super pressured formations, the following recommendations cover most of the present hazardous areas.

The recommendations are listed in approximate order of importance.

1. All well-control techniques start with the ability of the supervisor and the driller to control the equipment and the pressures. In wells that drill geopressured formations, the USGS OCS Orders should be strictly followed as an example of reasonable and safe drilling procedures. There is no other standard that is as complete or has been tested to the extent of these orders.

2. Crews and supervisory personnel should fulfill the training classes of GSS-OCS-T 1.

3. An instrument package comparable to the manned data collection and data analysis units provided by some of the major service companies should be used on wildcat wells or on

any geopressured well where engineering supervision for well response is not on a 24 hour basis. There are degrees of geopressuring, so that this statement should not be construed to cover all wells in the geopressured zones, but only those where the extreme or super pressures are the drilling target.

4. All blowouts start as a well kick. There are two types of equipment in general use to detect the well kick, the flow sensor and the pit volume totalizer. All indirect evidence indicates that these two types of equipment are not effective or that the drillers display is not adequate. The detection of well kicks needs to be improved with more effective and reliable equipment.

5. Well-control instruments in general need to be investigated to ascertain their reliability in the higher temperatures of geopressure drilling (into the super pressures and temperatures). The subject of instrument reliability is also discussed in the section of this report covering geothermal drilling.

6. Equipment failures due to high-temperature geopressured fluid are an unknown factor. The experience at the Delcambre well for D.O.E. indicates that temperature problems may be significant. The manufacturers contacted in the course of this study had done little to investigate this aspect to geothermal development with lower pressures and high temperatures, or to temperatures below 300°F. To the degree that high-temperature/high-pressure work is contemplated by D.O.E., there needs to be some standards of performance established for the blowout preventer and other allied control equipment.

7. A guidance manual for Federal personnel engaged in geopressure drilling needs to be developed. At present, there is no such guide available and experience is passed along by

reports or personnel contact. The whole field of geopressure drilling, which encompasses much more than this report, depends upon proper well programming and supervision as well as a good understanding of the limits of the drilling system.

As the D.O.E. continues to explore the upper limits of fluid pressures in the earth, it will become necessary to develop a tightly reasoned, and experience oriented guide for personnel dealing with the hazardous geopressured well.

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GEOTHERMAL BLOWOUT CONTROL

PHASE II

PROGRAM PLAN FOR GEOTHERMAL BLOWOUT CONTROL

by

**William A. Rehm
W. C. Goins, Jr.**

prepared for

**U.S. DEPARTMENT OF ENERGY
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MEI REPORT - TR78-27 (Book 3)

ABSTRACT

This report presents a comprehensive program to improve blowout control procedures and equipment in geothermal drilling. The objective of the outlined program is to develop the elements that will lead to a more assured safe drilling program. Areas addressed in this study involve training and drills, procedures, and equipment where shortfalls are evident in blowout control operations for geothermal drilling.

SUMMARY

The hazard of a blowout in geothermal drilling is relatively modest. While it is possible to postulate a major blowout from a worst-case analysis, the pressures, temperatures, and gases have just begun to be encountered that would make this a reasonable supposition. Continued geothermal drilling will lead into these hazardous areas and steps should be taken now to obtain the equipment and techniques to handle the extreme temperatures that will occur.

Research sponsored by the DOE-DGE is aimed at developing the technology required to reduce the risk and cost of potential blowouts. The program proposed in this report and summarized in Table 1 includes training and drills, procedures, and the development of equipment that will be needed to control the very high temperature well.

The basic thrust of this report is in developing the basic tools for well control where shortfalls are evident. The basic effort in this development is in the short term, low cost area where concentrated effort will be effective is in immediate or short term rectification of a problem area or potential area.

Recommended total expenditures for a basic program over a five year period are \$7.5 million. This budget and time will provide for the development, demonstration, and technology transfer of improved geothermal blowout control procedure and equipment. .

Savings in excess of ten times the cost of the program can be expected from the outlined program without adding a dollar cost to the saving of crewmen from accidental steam burns. Figure 1 shows the benefit to cost ratio for the proposed blowout control program on a dollar basis but does not attempt to include the savings on accidents to the crew.

TABLE 1
PROPOSED BUDGET
GEOTHERMAL BLOWOUT CONTROL
(000 omitted)

	FY79	FY80	FY81	FY82	FY83
1. Well Control Training	-				
2. Well Control Drills	-				
3. Equipment Temperature Standards	90	60	(75) ⁴		
4. Instrument Temperature Standards ¹	45	30	(35) ⁴		
5. Deflector/Diverter Head	60	30			
6. Pressured Mud Heat Exchanger	30	70	25		
	225	130	25		
7. Drilling Head	100	250	250 ²		
8. Remote Operated Drill Rig	75	75	1250 ²	1250 ²	500 ³
	400	455	1525	1250	500

¹project shared with geopressure

²cost defrayed 50% by industry participation

³cost defrayed 50% by drilling contracts

⁴possible add on

FIGURE 1
RATIO OF BENEFITS DERIVED/COST EXPENDED
FOR GEOTHERMAL WELL CONTROL PROGRAM¹

¹This does not include Items 7 and 8.

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GEOTHERMAL BLOWOUT CONTROL

PHASE II

PROGRAM PLAN FOR GEOTHERMAL BLOWOUT CONTROL

PROCEDURES AND EQUIPMENT

The Geothermal Blowout Control Study, Phase I has pointed out that it is difficult to document shortfalls in geothermal drilling because there have essentially been no blowouts in geothermal drilling that could be attributed to the drilling process. This has been due, at least in part, to drilling geothermal reservoirs that have been low or subnormally pressured and that have had moderate temperatures. As the search for geothermal resources goes towards higher temperature formations, and possibly formations with higher pressures, there are certain projects that should be undertaken that would limit the risk of having a blowout.

Geothermal Blowout Control PHASE I listed 8 recommendations for improving the safety of geothermal well control operations (Table 2). Two of the recommendations are administrative in nature since they involve drills and procedures. Two of the recommendations are surveys since they suggest that available equipment and instruments should be listed by the manufacturer for temperature tolerance. Two more recommendations deal with development of geothermal well control equipment, or the modification of existing equipment to meet the problems of reliability in high temperatures. The final two recommendations deal with equipment not available that will be needed for very hot wells.

TABLE 2

GEOTHERMAL BLOWOUT CONTROL
RECOMMENDATIONS FOR ELIMINATING AREAS OF
SHORTFALLS IN GEOTHERMAL BLOWOUT CONTROL

IMMEDIATE PRIORITY

1. Well Control Training
2. Well Control Drills

PRIORITY ONE

3. Equipment Temperature Standards
4. Instrument Temperature Standards

PRIORITY TWO

5. Deflector/Diverter Head
6. Pressurized Mud Heat Exchanger

PRIORITY THREE

7. Drilling Head
8. Remote Operated Drill Rig

The development of the program plan for shortfalls in blowout control for geothermal drilling must take into account the effort at present being made to develop a high-temperature elastomer to replace the presently used seals and packers. In that regard, this report assumes that the research for the high-temperature packer and seal elastomer will only be partly successful, and certain other developments need to be made to provide an alternate method of controlling high-temperature wells without the use of heavy high-temperature elastomer packer elements.

In the development of these recommendations, an attempt was made to set priorities in the order that action should be taken. All of the projects are independently based so that action could be started on a parallel mode. However, there are some obvious efforts that will produce results more quickly and for less of an investment in time and money and these were given the highest priority. The lowest priority was given to the two projects where equipment is needed for future very hot wells, but the availability of that equipment would not effect geothermal drilling in the next few years (Table 2).

The projects were set in priority ranking by the following rules:

1) Immediate Priority

Items that could be immediately remedied by an administrative action since all the elements were available but not utilized.

2) Priority One

Items for which there is an immediate need, and where information or equipment could be utilized as soon as available.

3) Priority Two

Items where the shortfall in blowout control elements was apparent, but a project where development work was required. These are development projects that have a high potential for success at a modest cost.

4) Priority Three

Items where there is a long term need, and in the case of these projects, it is doubtful that very high-temperature wells can be safely drilled without the specified equipment. However, there is no immediate need for the equipment even though it could be used at present and probably reduce the hazard to the rig personnel.

BENEFIT ANALYSIS

In order to evaluate the Geothermal Blowout Control Program proposed in this study, it was necessary to estimate the number of geothermal wells which would be drilled during the next 10 years and the savings which would accrue by implementing this program. A study¹ by the Mitre Corporation indicated that over 5,000 wells would have to be drilled in the next 10 years in order to meet the national goal of 10,000 megawatts of electric power on line by the year 2000. The Mitre estimate of the number of wells required each year was used in this analysis. Based on these figures, an estimate of an average of 126 drill rigs would be required if the wells were drilled and completed in an average of three months each.

Cost figures, published by Glass², indicate that a typical well in the Geysers costs about \$1,000,000 and that a typical well in the Imperial Valley costs about \$550,000. Thus in 1977 average geothermal well costs were approximately \$700,000.

Geothermal drilling is not typical of U.S. oilwell drilling because of the preponderance of soft sediments. It might, however, be considered similar to Canadian drilling in hard and broken rock. The Canadian rigs have a 2% frequency for blowouts.³ Assuming on the basis of this study that geothermal drilling would be only half as hazardous, this would indicate the statistical chance for one blowout per 100 drill rigs per year.

TABLE 3
PROPOSED BUDGET
GEOTHERMAL BLOWOUT CONTROL
(000 omitted)

	FY79	FY80	FY81	FY82	FY83
1. Well Control Training					
2. Well Control Drills					
3. Equipment Temperature Standards	90	60	(75) ⁴		
4. Instrument Temperature Standards	45	30	(35) ^{1 4}		
5. Deflector/Diverter Head	60	30			
6. Pressured Mud Heat Exchanger	30	70	25		
	225	130	25		
7. Drilling Head	100	250	250 ²		
8. Remote Operated Drill Rig	75	75	1250 ²	1250 ²	500 ³
	400	455	1525	1250	500

¹project showed with geopressure

²cost defrayed 50% by industry participation

³cost defrayed 50% by drilling contracts

⁴possible add on

TABLE 4

SUMMARY OF PROGRAM COSTS AND BENEFIT ANALYSIS

Year	79	80	81	82	83	84	85	86	87	88
No. of Wells ¹	51	124	179	211	316	330	773	817	588	1,922
No. of Rigs	13	31	45	53	79	83	193	204	147	480
No. of Blowouts	.1	.3	.5	.5	.8	.8	1.9	2	1.5	5
Cost of Blowouts (000)	210	630	1,050	1,050	1,680	1,680	3,990	4,200	3,150	
Cost of Blowouts Cumulative (000)	210	840	1,890	2,940	4,620	6,300	10,290	14,490	17,640	
Project Cost (000)	225	130	25							
Project Cost Cumulative (000)	225	355	380	380	380					
Benefit/Cost Ratio	.9	2.3	5.0	7.7	12.1					

Basis of Calculations

1. Constant 1977 \$
2. \$700,000 Well Cost and $\$2.1 \times 10^6$ Blowout Costs
3. Each Rig Will Drill and Complete a Hole Every 90 Days on a Yearly Average
4. Blowouts Will Occur on a Rig Frequency of 1%

FIGURE 1
RATIO OF BENEFITS DERIVED/COST EXPENDED
FOR GEOTHERMAL WELL CONTROL PROGRAM¹

¹This does not include Items 7 and 8.

IMMEDIATE PRIORITY FOR GEOTHERMAL WELL CONTROL

Project #1. Drill crews and supervisors on geothermal liquid phase wells should successfully complete well-control courses in the constant bottom hole pressure technique modified after GSS-OCS-T 1.

The well control training required by the U.S.G.S. for Offshore drilling is quickly becoming the standard for all drilling. Geothermal does not provide the hazard of high-pressure gas, but the temperatures and pressures especially in some of the Utah Wells are high enough to cause lost circulation and downhole blowouts, or burn the crew if the water and steam is released at the surface.

There is no good reason, either practical or economic, that would preclude geothermal drill crews, especially those working on Federal lands, from learning how to control a well on choke without harming the well or causing damage or injury at the surface. The U.S.G.S. Geothermal Regulations, do not preclude this type of training, but leave to the operator the responsibility of well control.

Action can be taken on this recommendation for drill rigs drilling liquid phase wells by administrative action without significant delay or increase in cost of drilling.

Project 2. Drilling crews and supervisors on all geothermal wells should practice well killing or control procedures suitable to the reservoir and location tourly until proficient and thereafter at least once a week.

Well control equipment and techniques, however simple, will not work unless applied. There is no reason why the crew and supervisor should not be tested the same as the well blowout preventers and air breathing packs.

Action can be taken on this recommendation for all drill crews in geothermal drilling by administrative action and without significant delay or increase in the cost of drilling.

PRIORITY ONE DEVELOPMENT OF GEOTHERMAL WELL CONTROL EQUIPMENT

Priority one development work was defined as an area where a clear and immediate need exists.

Project #1. The development of high temperature operating data for standard well control equipment.

There is very little information available concerning the suitability of standard well control equipment (as defined in Phase I of this report) for high temperature operation. The purpose of this highest priority project is to develop a set of temperature, pressure, and flow standards for a worst-case or rational worst-case situation and request the manufacturers to evaluate their equipment against these standards. The manufacturers certification that the equipment meets the standards, or that certain modifications meets the standards, will provide a base for use of equipment in extreme geothermal conditions. If the manufacturer is unable to develop the information, a project may have to be initiated to develop the data so as to avoid equipment that is basically unsuited for a geothermal application.

PROGRAM

- 1) Identify well control equipment and develop the temperature, pressure, and flow standards for evaluation of well control equipment.

Time Required: Six Months

Cost: \$60,000

- 2) Appraise manufacturers of standards and request specific information and/or certification that standards are met.

Time Required: Six to Nine Months

Cost: \$60,000

- 3) Compile report and make recommendations for further testing if needed.

Time Required: Three Months

Cost: \$30,000

Total time and cost required for appraisal of equipment used in geothermal well control will be sixteen to eighteen months and a cost of \$150,000. Further add on costs may be desirable if the information is inadequate for standarization purposes.

Project #2. The development of high temperature operating data for standard well control instrumentation.

Without adequate instrumentation, there is no effective way of detecting a well kick early enough to avoid major well kicks or blowouts. This project is essentially similar to the instrumentation project reported under geopressure drilling where there is an immediate and pressing need for more reliable instrumentation and the two projects should be combined as a common development project.

Well control instrumentation, which includes gages, pit volume totalizing equipment, flow sensing equipment, gas

detectors, and fill-up systems for filling the hole when the drill pipe is pulled for a trip has a reputation for unreliability on normal drilling operations. There is every reason to believe that the reliability of this instrumentation is, under the temperature and humidity conditions of geothermal conditions, very poor.

Well control instrumentation has not been a critical item in drilling geothermal wells to date because there have not been any significant blowouts from drilling or have major gas problems arisen. This situation may change in the future and the equipment needs to be available to meet the problem. The basic equipment available at this time provides reasonable accuracy but, as pointed out, the reliability is poor. This in part is due to the low cost of the instrumentation, but the lack of reliability is also a function of design and operating procedures.

PROGRAM

- 1) Identify well control instrumentation and develop temperature, environmental, and safety standards for evaluation.

Time Required:	Six Months
Cost:	\$60,000

- 2) Appraise manufacturers standards and request specific information and/or certification that standards can be met.

Time Required:	Six Months
Cost:	\$60,000

3) Compile report and make recommendations
for further testing is needed.

Time Required: Three Months

Cost: \$30,000

Project Time: Fifteen Months

Estimated Cost: \$150,000

PRIORITY TWO DEVELOPMENT OF GEOTHERMAL WELL CONTROL EQUIPMENT

Priority two development work was defined as an area where a definite need exists and a short term relatively inexpensive development project can point the way or develop the solution.

Project #1. A low pressure, small, light, deflector head utilizing a nonelastomer partial seal needs to be developed to protect the rig crews from steam or steam unloading while drilling and tripping. The purpose of this device would be to provide protection against large quantities of steam when the sections of the drill string that will not go through a conventional stripping or drilling head are used or are being removed from the wellbore. The deflector would also be for use in those conditions where the temperature was too high for the elastomer of present drilling heads. The deflector would not have to seal tight but would provide a first line of deflection that could be utilized as a continual safety device or a temperature modifier for an upper seal.

At present, all of the steam diverter elements used depend upon an elastomer element that becomes brittle in high temperature service. Thus, it is difficult to strip the large stabilizers and other tools through the element without causing it to fail. In very high temperature operations the life of the stripping or deflecting element is very short and it becomes unreliable.

Research projects are attempting to develop packer elements that have higher temperature limitations. The results

of this research is still uncertain and in the meantime there is very little to protect the drilling crew as more extreme conditions are encountered.

PROGRAM

- 1) Develop operating specifications for the deflector head.
- 2) Survey available equipment and literature
 - for state-of-the-art, and equipment which could be modified.
- 3) Propose development program.

Time Required:	Nine Months
Cost:	\$70,000

(There may be equipment available from other industries, or new equipment available in the drilling industry that would be acceptable with some modification, so that a development program should not be undertaken until the results of the survey are evaluated.)

- 4) The development program for the deflector head would require design and manufacture of two deflectors or the modification of two existing pieces of equipment.

Time Required:	Six to Eighteen Months
Estimated Cost:	\$100,000 to \$250,000

- 5) Test programs are time consuming because of the necessity of finding an actual drilling operation that would have conditions approaching test requirements. Failing this, a simulated test situation would have to be established.

Time Required:	Six Months
Estimated Cost:	\$50,000

Project Time:	Eighteen to Twenty Months
Estimated Cost:	\$200,000 to \$400,000

Project #2. Drilling mud heat exchangers at present used in geothermal drilling are mud to air exchangers that in typical desert conditions reduce the mud temperature about 36°F. These have been adequate to date, but as geothermal wells are drilled into higher temperatures, it may be necessary to use a closed and pressurized system to prevent mud flashing and the buildup of mud solids or salts from the flashing. The mud to steam flashing would also endanger the rig crew.

Heat exchanger technology is adequate to develop systems that are more efficient and safer than the present mud to air exchangers.

PROGRAM

- 1) Develop operating specifications for a closed and pressured drilling mud heat exchanger.

Time Required: Six Months
Estimated Cost: \$30,000

- 2) Obtain modified exchanger from standard manufacturing design.

Time Required: Six Months
Estimated Cost: \$70,000

- 3) Test heat exchanger on geothermal drilling well.

Total Time Required: to Twelve Months
Test Time Required: One Month
Estimated Cost: \$25,000

Project Time: Twelve to Eighteen Months
Estimated Cost: \$125,000

PRIORITY THREE DEVELOPMENT OF GEOTHERMAL WELL CONTROL EQUIPMENT

Priority three was defined as the area of long term desirability. The project considered under this development category are probably possible and economically practical. There is a limited immediate need but as wells get hotter, the equipment will become essential.

Project #1. The drilling and stripping head is the heart of geothermal well control and rig safety. At present, research is being undertaken in the field of high-temperature elastomers for geothermal drilling. The end result of this research is uncertain and it might be well to have a joint industry/DOE project to guide the development of a high-temperature drilling; and stripping head that would be capable of worst-case temperatures.

PROGRAM

- 1) Develop operating specifications for a high-temperature drilling head that is not dependent on elastomer sealing.
- 2) Solicit industry participation in project.

Time Required:	Twelve Months
Estimated Cost:	\$100,000

3) Development of high-temperature drilling head.

Time Required: Twenty-four Months

Estimated Cost: \$1 x 10⁶

Project #2. As temperatures increases in geothermal drilling, the rig floor becomes more hazardous. Particularly in the case of well completions, workovers, and in trouble wells, the floor temperatures could become very high and the working environment hazardous. The long term development of high-temperature geothermal wells requires that the rig crewmen be removed from the rig floor and that the rig be operated remotely.

The drilling rig has been developed to the point where a remote operating rig is feasible from available equipment with very little further research work. It has not been economically attractive to put together a remotely operated rig because the crew is still necessary for maintenance and resupply, and the rig floor is not considered unreasonably hazardous.

In the case of very high-temperature geothermal well or workovers, the remotely operated rig will be a necessity because the drill pipe and rig floor will become too hot for normal crew operations during pipe pulling operations.

PROGRAM

- 1) Develop design and operating specifications for the remotely operated drilling rig capable of drilling to 10,000 feet.

- 2) Establish the availability of ready to use components.

Time Required: Twenty-four Months
Estimated Cost: \$150,000

- 3) Assemble rig with available components and
4) Develop interlock equipment.

Time Required: Twelve Months
Estimated Cost: $\$5 \times 10^6$

- 5) On site testing

Time Required: Twelve Months
Estimated Cost*: $\$1 \times 10^6$

*Costs may in part be defrayed by drilling operations.

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GEOPRESSURE BLOWOUT CONTROL

PHASE II

PROGRAM PLAN FOR GEOPRESSURE BLOWOUT CONTROL

by

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prepared for

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Under Contract No. EG-76-C-07-1603
Mod No. A003**

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MEI REPORT - TR78-27 (Book 4)

ABSTRACT

This report presents a program to improve blowout control procedures and equipment in geopressure drilling. The object of the outlined program is to develop the elements that will lead to a more assured safe drilling program. Areas addressed in this study involve training and drills, procedures, and equipment where shortfalls are evident in blowout control.

PROGRAM PLAN FOR GEOPRESSURE BLOWOUT CONTROL

SUMMARY

A safe and assured geopressure drilling program is at the very edge of the state-of-the-art and to assure the safe drilling of the extremely hot, deep, and pressured well requires strong supervisory control and improved detection equipment.

Geopressure drilling is hazardous because of the extreme pressures and the presence of flammable gas. It is difficult on paper to explain the relative paradoxes of dealing with a geopressured well. Despite the difficulty of interpreting the conditions deep in the ground, the geopressured well can be kept under control by the mud system in conjunction with a good casing program. Even if the well kicks, it can be controlled in a simple and straight forward manner. However, an error in judgment or equipment that malfunctions at a critical moment can cause situations that are difficult to analyze and control.

The drilling personnel are the real key to avoiding blowouts. The following report on the Development Program for Geopressure Well Control reflects the importance of the people in the first series of recommendations. These indicate the training and information that are paramount to avoiding blowouts.

Further recommendations suggest that the detection equipment be made more reliable and that the unknown condition of the blowout control equipment under conditions of temperature and pressure be examined.

Finally the recommendation is made that a procedures and operations guide be made available to Federal personnel and their contractors.

Recommended total expenditures for a basic program over a five year period are \$790,000 (Table 1). This budget and time will provide for the development, demonstrations, and technology transfer for improved geopressure blowout control procedure and equipment.

Savings in excess of 90 times the cost of the program can be expected from the outlined program. Figure 1 shows the benefit to cost ratio for the proposed blowout control program.

TABLE 1
PROPOSED BUDGET
GEOPRESSURE BLOWOUT CONTROL
(000 omitted)

	FY79	FY80	FY81	FY82	FY83
1. Well Drilling Regulations	-				
2. Well Control Training	-				
3. Data Analysis on Site	(0)				
4. Equipment Temperature Standards	120	30	() ⁴		
5. Instrument Temperature Standards ¹	120	30	() ⁴		
6. Detection Equipment Improvement	160	40			
7. Operating and Standards Manual	140	90	20	20	20
	540	190	20	20	20

¹project shared with Geothermal

⁴possible add on

FIGURE 1

BENEFIT/COST ANALYSIS OF CUMULATIVE SAVINGS
FROM GEOPRESSURE SHORTFALL PROJECTS

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GEOPRESSURE BLOWOUT CONTROL

PHASE II

PROGRAM PLAN FOR GEOPRESSURE BLOWOUT CONTROL

PROCEDURES AND EQUIPMENT

The Geopressure Blowout Control Study, Phase I has pointed out the hazards of drilling into the geothermal pressures. The incidents of blowout appears to be close to 2% of the drilling rigs involved in drilling. It is not possible with the records available at this time to separate the blowouts due to geopressure from other blowouts, but the causes of blowouts and the solution to the problem are much the same in normal pressured zones and in geopressured zones.

What is readily apparent is that the hazard of a blowout is much greater as the well pressure increases and as the quantity of gas or light oil increases. The geopressed, super pressured zones that are the natural target of geopressured drilling are very hazardous drilling and every care needs to be taken to keep the well from kicking, and if the well kicks, to keep the influx into the wellbore small. Safe and assured geopressure drilling is at the very limit of the state-of-the-art. Since geopressures are a matter of degree, the deeper the zone is penetrated and the higher the pressure (and hotter) the greater the risk and the greater is the care that must be taken as the limits to the state-of-the-art are approached.

Geopressure Blowout Control, Phase I lists seven recommendations for improving the safety of geopressure well control operations (Table 1). The first two of the recommendations are administrative in nature and concern Federal Regulations that should be followed in the drilling of the super pressured well. The third recommendation concerns data analysis on the drilling location, but can be implemented by administrative action. The next two recommendations concern the development of information about the temperature sensitivity of geopressure equipment and instruments. The sixth recommendation suggests certain blowout detection equipment that needs to be improved, and the final recommendation points out the need for an operating and procedures manual to guide operations.

TABLE 1
PROPOSED BUDGET
GEOPRESSURE BLOWOUT CONTROL
(000 omitted)

	FY79	FY80	FY81	FY82	FY83
1. Well Drilling Regulations	-				
2. Well Control Training	-				
3. Data Analysis on Site	(0)				
4. Equipment Temperature Standards	120	30	() ⁴		
5. Instrument Temperature Standards ¹	120	30	() ⁴		
6. Detection Equipment Improvement	160	40			
7. Operating and Standards Manual	140	90	20	20	20
	540	190	20	20	20

¹project shared with Geothermal
⁴possible add on

The development of the program plan for reducing shortfalls in blowout control for geopressure drilling should help to reduce the frequency of blowouts by 50%. This could provide an annual saving of \$30,000,000 per year. It may be impractical to believe that all blowouts can be eliminated because of the problem of human error in dealing with earth pressures. It should be possible, however, to reduce the frequency and severity of the blowout.

PRIORITIES

In the development of these recommendations, an attempt was made to set priorities in the order that action should be taken. All of the projects are independently based so that action could be started on a parallel mode. However, there are some obvious efforts that will produce results more quickly and for less of an investment in time and money and these were given the highest priority (see Table 2).

TABLE 2

**GEOPRESSURE BLOWOUT CONTROL
RECOMMENDATIONS FOR ELIMINATING AREAS OF
SHORTFALLS IN GEOPRESSURE WELL CONTROL**

IMMEDIATE PRIORITY

1. Endorsing USGS OCS Drilling Regulations
2. Following USGS Blowout Control Training Regulations
3. Providing Onsite Data Analysis

PRIORITY ONE

1. Equipment Temperature and Pressure Standards
2. Instrument Temperature and Pressure Standards
3. Improvement to Blowout Detection Equipment

PRIORITY TWO

1. Development of a Drilling and Operations Standards Manual

The projects were set in priority ranking by the following rules:

1) Immediate Priority

Items that could be immediately remedied by an administrative action since all the elements were available but not utilized.

2) Priority One

Items for which there is an immediate need, and where information or equipment could be utilized as soon as available.

3) Priority Two

Items where the shortfalls in blowout control elements was apparent, but a project where development work was required. These are development projects that have a high potential for success at a modest cost.

BENEFIT ANALYSIS

The evaluation of the Geopressure Well Control Recommendations from a cost basis was made on the basis of the figures developed in Part V of Geopressure Well Control Part I. Within that section of the report, well kicks and blowouts were divided into four categories. They were:

A. Minor Well Kicks

Annual Cost to Industry \$1.2 million/year

B. Major Well Kicks

Annual Cost to Industry \$35.5 million/year

C. Minor Blowouts

Annual Cost to Industry \$12.8 million/year

D. Major Blowouts

Annual Cost to Industry \$15 million/year

The conclusion was the cost of blowouts to the industry, when the lost time for well kicks was included was on the order of \$60 million/year.

The frequency of well kicks and blowouts was based on the number of drilling rigs and was concluded to be about 2% of the operating drill rigs.

In the analysis that follows on Table 2 and Table 3, the assumption was made that 50% of the blowout could be eliminated or at least downgraded to minor well kicks. This assumes that

over the long term a saving of \$30 million/year could be made. The USGS requirements are being enforced on the wells in the Offshore Continental Shelf, and while that only involves a tenth of the rigs, the greater pressures and risks would seem to make it involve about one half of the money. The disproportionate share of the cost is due to the greater cost of the offshore rig, platforms and support. The result of these estimates is that at least \$15 million per year could be saved by proper handling of well kicks on the basis of the recommendations included in this report.

The priorities were based on time and cost of the individual project. Each of the seven projects is given an equal weight in the long term reduction of blowouts. The value of each project then is a potential savings of 1/7 of \$15 million per year or \$2.1 million/year.

Based on the proceeding analysis, the benefit/cost ratio is impressive (Figure 1). The benefits are so out of proportion to the costs that the indication is that either the projects should be undertaken immediately or that the analysis is in error.

FIGURE 1

BENEFIT/COST ANALYSIS OF CUMULATIVE SAVINGS
FROM GEOPRESSURE SHORTFALL PROJECTS

There is no reasonable doubt that the analysis is based on assumptions that are difficult to closely document, but even a 50% error in the assumptions leaves the benefit/cost ratio strongly biased towards immediate action.

TABLE 3
SUMMARY OF PROGRAM COSTS AND BENEFIT ANALYSIS

Year	79	80	81	82	83
No. of Rigs	2,200	2,400	2,700	2,900	3,200
No. of Blowouts or Well Kicks	44	48	54	58	64
Cost of Preventable Blowouts (000)	\$15,000	Cost Remains Constant - - - -			
Cost Cumulative (000)	\$15,000	\$30,000	\$45,000	\$60,000	\$75,000
Cost of Project (000)	540	190	20	20	20
Cost Cumulative (000)	540	730	750	770	790
Benefit/Cost Ratio	28	41	60	78	95

Basis of Calculations

1. Constant 1977 \$
2. 10% Increase in Rigs Annually
3. Cost of Blowouts will remain constant due to the efforts of the USGS in OCS Leases
4. Blowouts and Well Kicks will occur on a Rig Frequency of 2%

IMMEDIATE PRIORITY

Immediate priority in this report is defined as immediate steps that can be taken administratively that will have little effect on the overall cost of the well, but that will significantly improve the safety or reduce the risk of the geopressured drilling project.

Project 1. All geopressured wells that are to drill into the super pressures in search of geopressure resources should abide by the USGS Drilling Orders for the OCS area that is closest to the groppressed resource involved. The orders that are directly concerned with the operation are Order #2 - Drilling; and Order #3 - Plugging and Abandonment. The USGS Orders are the best and most complete definitions of good and safe drilling practice that are publicly available and are accepted as such by the majority of the industry. Project 1 can be implemented by action in the drilling contract.

Project 2. All drilling personnel on the geopressure wells that are dealing with drilling and drilling supervision should be qualified under USGS Training Order T1. Project 2 can be implemented by action in the drilling contract.

Project 3. Geopressured wells drilling into the super pressured geopressured zone should utilize a data collection and analysis unit to collect the drilling and formation data and to interpret the down hole conditions and data. This equipment is available from several major service companies or can be provided by the operator. There should be, however, 24 hour service with an independent instrumentation system

that is manned by competent people to monitor the drilling/tripping functions of the drilling rig. Project 3 can be implemented by action in the drilling contract. The cost of this service is approximately \$1,000/day.

Measuring the cost measured of this service against the estimated cost of \$150,000 for a single major well kick provides a minimum benefit to cost ratio of 2. The data collection unit, however, acts primarily in a drilling evaluation and data collection function, and so it is not subject to a benefit/cost analysis based solely on blowout control.

PRIORITY ONE DEVELOPMENT OF GEOPRESSURE WELL CONTROL EQUIPMENT

Priority one development work was defined as an area where a clear and immediate need exists.

Project 1. The development of high temperature operating data for standard well control equipment.

There is very little information available concerning the suitability of standard well control equipment (as defined in Phase I of this report) for high-temperature operation. The purpose of this highest priority project is to develop a set of temperature, pressure, and flow standards for a worst-case situation and request the manufacturers to evaluate their equipment against these standards. The manufacturers certification that the equipment meets the standards, or that certain modifications meets the standards, will provide a base for use of equipment in extreme geothermal conditions. If the manufacturer is unable to develop the information, a project may have to be initiated to develop the data so as to avoid equipment that is basically unsuited for a geopressure application.

PROGRAM

- 1) Identify well control equipment and develop the temperature, pressure, and flow standards for evaluation of well control equipment.

Time Required:

Six Months

Cost:

\$60,000

- 2) Appraise manufacturers of standards and request specific information and/or certification that standards are met.

Time Required: Six to Nine Months

Cost: \$60,000

- 3) Compile report and make recommendations for further testing if needed.

Time Required: Three Months

Cost: \$30,000

Total time and cost required for appraisal of equipment used in geopressure well control will be sixteen to eighteen months and a cost of \$150,000. Further add on costs may be desirable if the information is inadequate for standarization purposes.

Project 2. The development of high temperature operating data for standard well control instrumentation.

Without adequate instrumentation, there is no effective way of detecting a well kick early enough to avoid major well kicks or blowouts. This project is essentially similar to the instrumentation project reported under geothermal drilling where there is a need for more reliable instrumentation and the two projects should be combined as a common development project.

Well control instrumentation, which includes gages, pit volume totalizing equipment, flow sensing equipment, gas detectors, and fill-up systems for filling the hole when the

drill pipe is pulled for a trip has a reputation for unreliability on normal drilling operations. There is every reason to believe that the reliability of this instrumentation under the temperature and humidity conditions of geopressure conditions is very poor. In this project mud flow detectors and pit volume totalizers are treated separately under Project #3.

PROGRAM

- 1) Identify well control instrumentation and develop temperature, environmental, and safety standards for evaluation.

Time Required:	Six Months
Cost:	\$60,000

- 2) Appraise manufacturers standards and request specific information and/or certification that standards can be met.

Time Required:	Six Months
Cost:	\$60,000

- 3) Compile report and make recommendations for further testing that is needed.

Time Required:	Three Months
Cost:	\$30,000

Project Time:	Fifteen Months
Estimated Cost:	\$150,000

Project 3. Development of more reliable and useable flow sensors and pit volume totalizers.

The flow sensor and pit volume totalizer are basic tools for detecting the potential blowout. They are only moderately effective probably because of lack of reliability and an ineffective drillers console display. Since the detection of a potential blowout is a major step in the reduction of blowouts, and since the difficulty of dealing with a potential blowout, increases with the size of the well kick, it is essential to have quick, accurate, early warning.

The project to increase the effectiveness and reliability should analyze the available equipment in conjunction with the manufacturers and users so as to obtain a firm grasp on the practical problems of reliability and accuracy. The manufacturers should be encouraged to make the changes or improvements to their equipment so as to have a whole generation of more effective detection equipment.

PROGRAM

- 1) Analyze present equipment and develop operating standards for reliability and display.

Time Required:	Six Months
Estimated Cost:	\$60,000

- 2) Develop improved models of flow sensor and pit volume totalizers.

Time Required:	Six Months
Estimated Cost:	\$100,000

- 3) Test equipment on drilling locations selected for extreme conditions.

Time Required:	Nine Months
Estimated Cost:	\$40,000

The cost of the project over a twenty-one month period would be \$200,000. During the same period, the analysis indicates that preventable blowout and well kicks will cost \$26 million. If improved detection equipment could save 1/7 of the well kicks from turning into major well kicks or blowouts the benefit/cost ratio would be 18/1.

PRIORITY TWO DEVELOPMENT OF GEOPRESSURE WELL CONTROL EQUIPMENT

Project 1. Development of an operating procedures and well design manual for Federal Personnel participating in geopressure drilling.

There is at present no available public source of information, procedures, practice, and experience in drilling the very deep, hot, high pressured geothermal well. As DOE participation in this type of endeavor increases, and as other small operators undertake DOE contracts, there needs to be a standard to aid in distributing the theory, knowledge, and experience in geopressure drilling. The hazards of a blowout cannot be reduced until there is some catalog of general knowledge and experience to work with.

PROGRAM

- 1) Prepare an outline and standard format
contact potential authors.

Time Required:	Six Months
Estimated Cost:	\$70,000

- 2) Authors develop the Chapters.

Time Required:	Nine Months
Estimated Cost:	\$100,000

3) Develop the Manual

Time Required:	Six Months
Estimated Cost:	\$60,000

4) Annual Evaluation

Time Required:	Two Months Each Year
Estimated Cost:	\$20,000

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