DEVELOPMENT OF BLOWOUT FIRE SUPPRESSION TECHNOLOGY

John G. O'Neill
National Bureau of Standards
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The work described herein was undertaken to determine if advanced fire suppression technology could lessen the incidence, effect, and duration of fires which eminate from wellheads. This report is an analysis of blowout fires resulting from OCS operations. Having completed it, the principal investigator is commencing his studies of the application of fire suppression technology.

If you wish to comment on the report or desire additional information, please contact either the principal investigator or the Research Program Manager.

Mr. John G. O'Neill
Center for Fire Research
National Bureau of Standards
Washington, D.C. 20234

Mr. John B. Gregory
Research Program Manager
Conservation Division
National Center, MS 620
Reston, Virginia 22092
703/860-6736

UNITED STATES DEPARTMENT OF COMMERCE
National Bureau of Standards
Washington, D.C. 20234

LETTER REPORT

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John G. O'Neill

Abstract

The Center for Fire Research is conducting a research program for the development of blowout fire suppression system technology for offshore oil and gas platforms and rigs. The initial study consisted of an examination of offshore drilling and production operations and current well control technology to identify the conditions which can precipitate blowout fires. In addition, an analysis was made of recent blowout fire incidents which occurred in the outer continental shelf of the U.S. This review concentrated on the technical information available to the researcher concerning the well conditions leading up to the blowout fire, the location on the platform of the hydrocarbon fire, and a description of the damage. A research program consisting of scaled experimental fire tests is recommended to develop blowout fire suppression system technology with the primary objective of extinguishing the fire before structural failure of the platform which further complicates the extinguishment process. Such a technology should enable safer and more rapid efforts to regain well control, thereby minimizing life safety hazards, damage to the platform or rig and reducing the down time of the facility.

Key words: Blowout; fire suppression systems; gas fires; offshore fire protection; petroleum fires.

1. Introduction

The Center for Fire Research (CFR) at the National Bureau of Standards (NBS) is conducting research into the development of a fire suppression system technology for offshore oil and gas platforms. The investigation is prompted by the need to maintain and improve the safety of oil and gas production on the outer continental shelf (OCS) and to minimize the possibility of losses to offshore equipment and structures. The research project is currently planned as a three year program. This is a report of the first year's work which consisted of an analysis of blowout fire hazards on offshore platforms and the development of the initial experimental plan to develop the fire suppression system technology.

Due to efforts in the United States to reduce the dependence on imported oil and gas, the exploration for oil and gas has increased dramatically. Industry reports indicate that drilling activity is at a record level, up 15.6% from last year. Drilling rig utilization rates in North America are at 98.2% in 1980 as compared to 89.4% in 1979 [1][1].

The increase in offshore activity is best exemplified in the Gulf of Mexico which is currently the major offshore exploration and production area in the U.S. But in addition to this, increased offshore exploration is evident off the east coast of the United States in the "Baltimore Canyon" area and in the waters off the coast of Alaska.

As the activity extends to deeper waters in the Gulf of Mexico and into the more hostile weather environments off the Atlantic coasts and in the Alaskan waters, the complexity and costs of the drilling rigs and platforms are increasing. Historically the practice has been to erect a number of platforms in a production area, each dedicated to a given function; e.g., drilling, production gas injection or compression and personnel quarters. However, this is not feasible in deeper waters where platforms are now being planned for water depths of 1000 to 1500 feet, or in the more hostile environments where construction time on site must be minimized. It is more desirable in these offshore environments to combine several functions, such as drilling, production and personnel quarters on a single platform. The single platform of this type represents a significant investment costing in the tens of millions of dollars, and also represents a significantly higher risk to life safety and facility protection in the event of a single fire or explosion than is the risk of a single incident on a traditional, smaller platform.

The risk of a catastrophic event such as a blowout fire on a large multifunctional platform can be considered an unacceptable risk. Such a perception suggests that a broad range of technologies should be examined to determine their feasibility to help prevent such an unacceptable catastrophic event. The purpose of this program is to examine and develop feasible technologies to minimize the impact of one type of catastrophic event on an offshore platform or rig, the blowout fire occurring on the platform. Fires resulting from subsea blowouts are not included in the current scope.

2. Unique Characteristics of Offshore Fire Hazards

Fire and explosion hazards are inherent in petroleum operations. Offshore platforms, particularly those for wellhead or production operations have many of the same inherent hazards as any land operations of the same types. However, the hazards on offshore platforms are compounded by environmental conditions, the unique arrangement of facilities, and the limited availability of outside fire fighting support. For example, salt-air corrosion continuously attacks the structure and the machinery on the platform; thus, the reliability of piping

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[1] Numbers in brackets indicate the literature references at the end of this report.

systems, pressure vessels, and controls may be adversely affected. In addition, as varying functions are combined on single platforms, operations become more enclosed in the cold climates, and the number of personnel increases, the potential for life and property loss resulting from a single catastrophic fire or explosion becomes much higher for offshore than for land based petroleum operations. Controlling actions to minimize the losses resulting from such incidents can also be complicated by adverse weather conditions, and by the relatively long distance to shore based support services. A secondary but significant impact of an offshore catastrophic fire and explosion is the risk of subsequent environmental pollution.

2.1 Drilling Blowout Fire Hazards

Of all the potential catastrophic fire hazards, a blowout fire remains as one of the most serious threats. Conditions necessary for a blowout in a well result when the pressure exerted by a column of drilling fluid is less than the fluid pressure in a permeable formation which has been penetrated by the bit. This influx into the wellbore is called a "kick".

Kicks occur due to a number of situations which can result in the formation of pressures exceeding the hydrostatic pressure of the drilling fluid (called mud) in the wellbore. The more dominant causes of kicks are briefly described as follows:

a. Insufficient weight of drilling mud in the wellbore is the most common;

b. Insufficient compensation of drilling mud in the wellbore when the drill string is removed from the well; for example when the drill string is removed to change a drilling bit, the hydrostatic pressure in the wellbore decreases as the level of the mud column decreases. As the drill string is pulled from the well additional mud must be added to compensate for the displacement of the drill string.

c. Negative pressure below the drill bit resulting from removal of the drill pipe in the well reduces the hydrostatic pressure of the mud in the well; this reduction, sometimes referred to as a swabbing effect, may allow an influx of formation fluids into the well.

The occurrences of kicks are very common during the drilling operations and a whole host of technologies including hardware and training have been developed to safely deal with this phenomena. However, the procedural aspects of dealing with kicks is much more complex in deep water drilling [2]. The complexity of deep water drilling is best represented in one type of kick described above where the pressure due to the density of the drilling mud in the well is less than the formation pressure penetrated by the bit. To prevent this the drilling procedure must maintain a high enough equivalent weight in the well to prevent the influx. In the gulf area, the normal formation pressure, which increases with depth, exhibits a pressure gradient of 0.45 lbs/in^2-ft. (In other areas the normal formation pressure may vary from 0.45 to 0.5 lbs/in^2-ft) [3]. Therefore, at a depth of 12,500 feet the normal formation pressure is 5812.5 lb/in^2. The drilling operation will attempt to maintain slightly higher hydrostatic pressure in the wellbore to prevent the influx of formation fluids into the well by regulating the density of drilling mud in the well. If an unexpectedly higher formation pressure is encountered and a kick occurs, one remedial action is to increase the hydrostatic pressure in the well by increasing the density of the drilling mud.

To the uninformed, one preventive measure might be to maintain a relatively high density of mud in the well which would overcome any unusually high formation pressures. However, excessively dense mud cannot be indiscriminantly applied since the pressure in the wellbore should not exceed the fracture pressure of the open well.

The fracture pressure is the pressure at which an exposed subsurface formation will rupture and accept whole mud or other fluids from the wellbore [3]. Exceeding the fracture gradient can have catastrophic results. The drilling mud which maintains the basic pressure control in the well could be lost through the fracture. If this loss cannot be compensated for, then the well is vulnerable to a large influx of formation fluids which would rise to the top of the well and precipitate a blowout. The combination of the fractured well surface and the influx of formation fluids at another location in the well can lead to the most critical well control problem, an underground blowout. In this instance the formation fluids which have entered the well because of insufficient mud, escape through the fracture and seep to the surface. This movement of high pressure fluid can greatly weaken the soil structure and cause a cratering effect at the surface. Subsurface blowouts of this nature offshore have caused drilling platforms to topple due to the cratering of the seabed [4]. Such a blowout often requires drilling a relief well which can take weeks or months to accomplish, at considerable cost and effort.

In deep water drilling, the problem of carefully maintaining the proper well pressure is further complicated by the fact that the fracture gradients are less than those observed on land or in shallow water at equivalent depths. The reason for this reduction is at least in part due to the marine sediments which have a lower fracture resistance than do land formations down to several thousand feet below the mudline [5].

Surface casing which consists of steel tubing in varying diameters is placed in the well to insure the structural integrity of the interior surfaces of the well and to serve as a conduit for the recirculating drilling mud. Figure 1 shows a typical offshore well with the arrangement of concentric casings which are installed as the drilling progresses. The risk of an underground blowout is greatest when a kick occurs with an insufficient amount of casing in the well. Normal procedures for dealing with kicks include shutting in the well, i.e. activating blowout preventers (BOP) which seal off the annulus of the well, while the kick is circulated safely out of the well and corrective measures are taken to regain well control with higher density muds and relieving the overpressure through a choke assembly. However, when there is insufficient casing in the well, particularly in the shallow portions, the well cannot be shut in because the fracture gradient of the unlined portion of the well can be exceeded, causing an underground blowout. In such cases, and as required by U.S. Geological Survey (USGS) regulations, divertor lines are installed on the platform to quickly relieve the overpressure in the well.

Once the well has reached the stage where sufficient casing is installed and the danger of exceeding the fracture gradient is not so great, the well is then shut in when a kick occurs. Typically, the procedure to regain control of the well includes relieving the excessive pressure through a choke assembly. A typical choke assembly design, as shown in figure 2, is an array of piping with elbows, valves (usually remotely controlled) and orifices, all designed to resist flow and therefore reduce the residual pressure of the vented hydrocarbons or mud/hydrocarbon mixes. On a seabed supported platform such as fixed legged platforms and jack up rigs, the BOP is located on the platform itself, just below the derrick, amidst the derrick substructure, just as drilling platforms on land. The BOP's on floating platforms such as semisubmersible rigs and drilling ships, however, are located on the seabed. In both cases the choke line assemblies are located on the platform itself. (The long choke lines extending from subsurface BOP's to the platform act also to restrict flow and reduce pressure.)

The procedures described above assume all equipment is operating properly and that the drilling crew is able to accurately measure pressure conditions, and also has the time to carry out the procedures of safely maintaining control over the well. This, as the record indicates, is not always the case. Therefore, other valves and seals are arranged in the BOP, including a pipe ram which seals off the annulus around the drill pipe, and a blind ram which is designed to seal off the well with the drill pipe out of the well. In some cases, often dependent on the practices of the given organization, a shear blind ram is included in the BOP stack and it is designed to actually cut the drill pipe and seal off the well. Shear-blind rams are usually installed only on subsurface BOP stacks with floating drilling vessels.

It is possible in the case of a kick to experience reverse flow in the drill pipe where the high pressure formation fluid displaces the mud and causes a blowout through the drill pipe. It is common for a manually operating valve to be stationed on the drilling floor and in the case of a potential blowout the valve can be attached to the end of the drill pipe.

It is not unusual during offshore drilling to have gas influxes which result in pressures exceeding 6,000 lb/in^2 at the surface. These high pressures present a significant challenge to the components of the BOP' stack, the choke assemblies, valves and the other equipment counted on to safely deal with these pressures on the platform. Although the equipment is designed to handle such pressures, the rigorous environment in which it must function, particularly for offshore use, make failures inevitable. For instance, the internal surfaces of the choke assembly are exposed to kick fluids including pieces of rock or shale moving at very high velocities. Since the purpose of a choke assembly is to resist flow in order to permit a safe venting of kick fluids, the choke orifices, valves and elbows are subjected to high internal reaction pressures. Failures of critical components on the platform when exposed to hydrocarbons at such high pressure present a significant hazard in the wellhead area. The risk of damage is not only significant in terms of potential life and property loss but regaining well control through surface capping techniques may be impossible because of critical equipment failure and inability to gain access to the well.

2.2 Production Blowout Fire Hazards

Once the well is completed, production tubing placed in the well and the wellhead valve assembly is installed, the potential for blowout is essentially minimized. Fires and explosions can occur due to hydrocarbons leaking from ruptured production piping, but the inherent dangers of maintaining pressure control during the drilling operation are no longer a problem.

Blowouts, however, can occur and have occurred during workovers of existing wells. A workover is any of a number of operations on a completed well to increase the production. Often, the surface and subsurface safety valves must be removed to permit access into the well. Examples of workover operations include deepening the well and pulling and resetting the well liner. A special workover mud is sometimes used to keep the well under control. In other cases a plug is inserted into the well to block off influxes into the worked over zone in the well. In other workover operations, the drill string is forced downward into a pressurized well by means of a snubbing unit. The snubbing unit includes a control head assembly used to provide a pressure seal between the casing (well liner) and the pipe. The control heads are essentially ram type blowout preventers and they are designed to maintain a seal around the pipe as it is raised and lowered in the well.

In all of these workover operations, particularly where plugs or snubbing units are employed, the safety of the operation against a potential blowout is solely dependent upon valve seals preventing the uncontrolled flow of hydrocarbons under high pressures. The proper operation and maintenance of this key equipment is essential. There are inherent risks associated with workovers because of the wide range of conditions encountered and the diverse operations actually carried out to stimulate production. The fact that the purpose of the workover is to increase the flow of the well suggests that there are uncertainties concerning dynamic pressure conditions associated with the operation.

3. Records of Blowout and Blowout Fire Incidents

The preceeding sections provided a generalized description of potential blowout problems and the current technologies for dealing with kicks to prevent a blowout. It is important to remember that there are complexities, beyond the brief description contained in this report, in applying these technologies, particularly in deep water drilling.

An appropriate analysis of the blowout fire hazard should include an examination of the record of incidents. The record addressed here is primarily based on the experience on the outer continental shelf of the U.S. A recent study of blowouts which occurred in the OCS during the period 1971 through 1978 was conducted by Danenberger for the USGS [6]. This study indicated that during this period 46 blowouts occurred in the OCS, all in the Gulf of Mexico. Of the 46, 30 occurred during drilling operations and eight of the remaining 16 occurred during workovers of completed wells. This record tracks closely with the assessment of the potential hazards as a function of the type of offshore operation, described in the previous sections. That is, the drilling and workover operations have inherent hazards due to the unexpected pressure conditions and the record verifies this assessment.

The CFR project included as part of the analysis of blowout fire hazards, an attempt to examine in detail those blowouts which resulted in serious fires. The purpose of this examination was to identify the technical nature of the problems which contributed to the severity of the damage such as, the location of the actual flow of hydrocarbons, estimation of the flow parameters, the structural damage incurred, and the duration of the incident. The information was obtained from USGS investigation reports and press releases. The completeness of the technical information varied from incident to incident. However, except for the estimated flow rate of hydrocarbons which fueled the fires, most of the data needed for this analysis was obtained from the reports. Data on flow rates were often impossible to obtain. In terms of the purposes of the USGS' investigations, which is to identify operational or equipment failures and to assess any pollution problems, data on the fuel flow as a measure of fire intensity were not probably considered essential information.

The investigation was limited to the period from 1973 to the present because of the availability of investigation reports from the USGS and because the more recent experience reflects the use of current technology hardware for well control on offshore platforms. It was judged that an examination of incidents prior to 1973 might not be fruitful since that experience would not reflect current well control methods and equipment.

From this record nine blowout fires were identified. Of the nine, six occurred during drilling, one during a workover, and 2 during production. A summary of each of the nine incidents is provided in Appendix A to this report.

Aside from the U.S. experience, there have been several blowout fire incidents during the past few years on offshore platforms and rigs in other countries which have had catastrophic results. One particular incident worth noting, is the blowout in Campeche Bay, Gulf of Mexico on June 3, 1979 [7]. A blowout occurred on a semisubmersible drilling rig while the drill string was being pulled out of the hole. The BOP on the seabed was activated but the shear rams could not cut the heavy, thick walled drill collars which were located in the BOP stack. Attempts to install a safety shut-off valve on the end of the drill pipe failed and oil and gas gushed out of the 3-1/2 in O.D. drill pipe. The gas and oil ignited and the subsequent fire destroyed the derrick structure, and the fire on the rig caused subsequent damage to the marine riser support. The marine riser, with the drill collar inside, collapsed and knocked the seabed BOP stack about 10° off center. The ensuing flow of oil and gas created one of the greatest recorded oil spills to date. The flow of oil and gas was finally stopped in March 1980, some nine months after the initial accident. It was estimated that the flow from the well was initially 50,000 barrels of oil and 100 million ft^3 of gas per day. When the well was finally sealed, more than 2.5 million barrels of oil was lost. The drilling rig had been damaged so extensively by the fire, it was towed further out to sea and sunk a few days after the initial incident.

Apparently there were several operational errors which contributed to catastrophe, and which were also contrary to U.S. regulations for the OCS. However, while an argument can be made that such a similar incident is highly unlikely to occur in the U.S. regulated offshore operations, the incident does demonstrate the potential consequences of a fire inflicting severe structural damage to an offshore platform or rig.

From this limited information concerning blowout fire incidents including the information in Appendix A, several important conclusions were drawn which will serve to influence the direction of this portion of the research program.

a. The frequency of blowouts and blowout fires was greatest during drilling operations.

b. The location of the actual flow of hydrocarbons in blowout fire incidents varied. The locations included the choke assembly, the end of the drill pipe on the drilling deck, the top of the annulus just below the rotary table and at flange connections in the BOP stack located in the substructure below the derrick.

c. The blowout fires burned for extended periods of time, in some cases, for several days. In several cases, the fires were extinguished by the well bridging over or by a column of water projected up through the well from the formation.

d. In dealing with blowouts, the surface capping approach was much preferable to drilling relief wells which typically required months to accomplish.

e. Structural collapse of the derrick and derrick substructure often occurred soon after the initial blowout fire. The collapsed structure greatly hampered surface capping measures, and the debris had to be cleared prior to the capping procedures.

4. Technology Improvements for Controlling Blowout Fires

As the record has indicated, the blowout fire on an offshore platform or rig represents a catastrophic event which has resulted in extensive damage to the structure and in some cases a total loss of the rig. Recent foreign blowout fire incidents have also resulted in large oil spills, resulting from the extensive damage to wellheads subsequent to the blowout fires.

The conclusions drawn from the analysis of these incidents suggest that if the structure in the vicinity of the wellhead, including the derrick and the derrick substructure, could maintain its integrity for the duration of the initial blowout fire, the following benefits could be derived:

a. Impact damage to the wellhead from falling structural members can be prevented.

b. Surface capping measures can be conducted more rapidly and safely in the absence of fallen structural members.

c. By limiting structural damage and shortening the time necessary for regaining well control, the costly down time in drilling and production activities can be minimized.

d. The overall risk of life loss, injury and pollution can be minimized by shortening the time necessary to regain well control.

At least two approaches have been identified in developing technologies necessary to accomplish the goal of maintaining structural integrity for the duration of the fire and regaining control of the well. The first approach is to extinguish the fire rapidly before the heat begins to deteriorate the structure. The second approach is to protect the structure from the heat until the fire can be extinguished.

4.1 Rapid Fire Extinction

In considering the first approach, the blowout fire presents several complex problems which must be addressed in developing a technology to accomplish rapid extinction. These include the following:

a. The location of the flow of hydrocarbons in a blowout fire can vary. The summary of incidents in the OCS given in Appendix A demonstrates this problem.

b. The flow rates of hydrocarbons and the composition of the fluids also vary, although there is sufficient evidence that the fluid in a blowout is by volume, primarily gas.

c. There are a very little data available concerning the performance of various extinguishing agents in suppressing large flowing hydrocarbon fires.

d. In a blowout fire, the extinction of fire must be carefully coordinated with measures being taken to terminate the flow. Otherwise, an accumulation of flammable gases may lead to a subsequent explosion which could cause greater damage than the original fire.

Taking these problems into consideration, two approaches to developing an extinction technology appear worthy of investigation, and are dependent on the conditions. The first deals with blowouts which originate from failure in the return conduit for drilling mud which include failures at flanges in the BOP stack (on the platform), and flow at the annulus cap and in the choke assembly. Since the fire could originate at several possible locations, a system which injects an inerting agent into the flow upstream of the failure can interrupt the fuel and cause a flame separation. This concept has been used in flare suppression systems on platforms in the North Sea. These systems are designed to quickly snuff out gas flares in case of an emergency, in particular a large gas leak. They are designed to inject an inerting agent into the gas flare line where the gas pressure has been generally reduced to not more than a few hundred lbs/in^2.

An injection system into annulus of a drilling riser, however, must act upon pressures up to 6000 to 7000 lb/in^2. The development of such a technology must begin by determining, through scaled experiments, the fluid mechanics involved with forcing an inerting agent into the hydrocarbon flow stream. CFR plans to conduct scaled down experimental work to develop an injection system for extinguishing this type of blowout fire. The concept of such a system is illustrated in figure 3.

The proposed research program will examine the use of various agents including water, nitrogen, and halon, and determine the parameters for injection of these agents into a flow stream of gas cut mud, gas, and gas-oil mixtures representative of fluids passing through the well annulus during the blowout. The design variables which will be quantified include the entry mechanism for the agent into the annulus, the delivery rate and the duration of the delivery necessary to accomplish flame extinction. The scale of the experimental fire tests will be increased to verify the performance of successful systems developed in the smaller scale tests.

The second approach to rapid fire extinction addresses conditions where blowout occurs through the drill pipe. Since the drill string is in virtual constant movement in the well, a fixed injection system, as suggested for the annulus, is not feasible for the fire originating from the flow of hydrocarbons up through the drill pipe. The problem resembles a large diffusion flame located at the derrick structure above the drilling floor. In estimating the amount of water required to extinguish such a fire, an approximate ratio can be developed to predict how much water is required to accomplish extinguishment either through heat absorption or oxygen dilution. It is estimated that a ratio of water flow rate (mass per unit time) to hydrocarbon rate would be 10 to 1 to accomplish extinguishment through heat absorption. A ratio of approximately 6 to 1 is estimated to accomplish extinguishment by oxygen dilution. The calculations are contained in Appendix B.

These ratios are estimates only and several important assumptions were included which if altered could actually raise these ratios significantly. For example, in the dilution calculation, steam must be generated. The heat absorption calculation assumes 100 percent efficiency of the water absorbing the heat. Neither calculation, on the other hand, takes into account the plume entrainment which is likely to enhance the performance of the water spray. As shown in figure 4 the large flowing hydrocarbon fire tends to entrain a tremendous amount of air into the combustion zone. It is envisioned that the entrained air can enhance the delivery of the extinguishing agent into the plume, as shown in figure 5.

There is no available quantitative information on the performance of other extinguishing agents for large flowing hydrocarbon fires. It is planned in this program, that scaled experiments be conducted, with water, dry chemical and other candidate agents to determine their performance against these fires. Considering the problem of structural integrity of the derrick exposed to these fires, data will also be obtained concerning the impact of various agents on limiting the temperature of structural steel in the vicinity of the fire.

In summary, this phase of the experimental effort will address both rapid extinction of the fire and the protection of structural steel. It is anticipated that outside consultants with suitable fire test facilities will conduct this part of the research program. These facilities would include the capability of conducting tests with flowing gas and gas/liquid fires. In the initial phase the scaling from estimated actual blowout fires to the experimental fires would be dependent upon the current facilities capability, thereby eliminating the need for an expensive burner installation for this primary work.

The primary objective of this phase is to develop an incipient fire extinguishing technology for drill pipe blowout fires above the drilling deck. A secondary objective will be to determine associated benefit of the extinguishing systems in reducing the heat transfer to adjacent structural steel. In the absence of fundamental information on this extinguishing concept, the progress will be heavily dependent upon intermediate results of scaled fire tests.

4.2 Maintaining Structural Integrity

In a flowing hydrocarbon fire, particularly when gas is the principal fuel, the extinguishment of the fire must be coordinated with measures to taken to stop the flow. Otherwise, conditions might be inadvertantly created where a larger, more serious secondary explosion and fire would occur. In a blowout fire situation offshore, considerable time might be required to bring resources to the scene to control the flow. Depending on the nature of the problem, these resources might include a new wellhead or mud pumping equipment. During this period, the structural integrity of the platform in the vicinity of the fire should be maintained.

In this context, the second principal area of focus in developing fire protection technology for blowout fires becomes equally important to rapid extinguishment, i.e., to protect the structure from the heat until the fire can be extinguished. In considering this approach the influence of high temperatures on steel needs to be examined. Structural steel begins to lose its yield strength as the temperature of the steel rises. Above 400°C the decrease in strength for typical structural steel becomes critical. In fires involving hydrocarbons, such as a blowout fire, temperatures in the area of the fire can be expected to reach 1100°C. Under these conditions the temperature of the steel can also be expected to reach temperatures far exceeding 400°C and, therefore structural integrity can be lost quickly. To prevent such a failure, the structure must be protected, to prevent the steel from exceeding 400°C.

For the blowout fire, as the record indicates, this protection must hold up for many hours, possibly days until the well can be recapped. However, conventional fire insulating coatings used to protect steel are not capable of enduring this type of fire. For example, Mobil Research and Development developed a test method to determine the fire resistance of steel coating materials [8]. The test method was developed in an effort to evaluate performance of fire resistive materials to petroleum fires which can be expected to be more intense than building fires. The total heat flux seen by the test specimen was estimated to be around 22 w/cm^2. When subjected to this heat flux, fire resistive coatings were found to provide up to 60 minutes protection for steel "I" beams. Obviously, blowout fires which typically last for several hours can be expected to overtax such protection.

4.2.1 Water Spray Protection of Structural Members

In addition to fire resistive coatings, automatic sprinkler deluge systems have been installed on some platforms in wellhead areas. These systems are designed to flow water simultaneously from an array of open sprinklers and cool the area in an effort to protect the structure. As far as has been determined in this investigation, these systems have often been installed on large combination drilling and production platforms in the North Sea and have not, in general, been installed on platforms or rigs in the OCS. (In the OCS, during a blowout fire support vessels are brought to scene to direct water spray on the structure and to prevent total collapse.) The system designs are based primarily on engineering judgement and there were no test data found during this investigation to support the deluge system design criteria for large hydrocarbon fires such as a blowout fire. These systems consist of spray nozzles located on the underside of decks and therefore, the degree of protection they offer for vertical structural members would appear inadequate.

The problem of protecting structural steel with sprinkler/deluge systems is still considered unsolved because of the many variables which influence the performance. Principal variables include the flame intensity, and the buoyant forces of the fire, which affect the movement of spray droplets from the sprinklers and their ability to impinge on the steel, cooling the surface. Other complex questions include the effect of local hot spots on the steel which are not cooled by the spray. Ongoing long range research programs are being conducted to address these questions and in the meantime, empirical tests must conducted to develop criteria for specific problems. Valid extrapolations of such empirical results for other structures and other types of fires are usually very limited.

The many unknowns associated with protection of steel with sprinkler systems considering the current state-of-the-art, makes valid analytical predictions of performance virtually impossible.

4.2.2 Water Filled Structural Members

One method of protecting structural steel columns, however, which overcomes many of the limitations described above, incorporates the use of water filled tubular members. Although the concept has been in existance for some time, it was only first applied in 1967 to steel columns in a high rise building [9]. As far as this investigation has determined, the concept has not been applied to offshore oil and gas rigs.

The concept of water filled columns is quite simple. Ideally, water inside a structural member exposed to a fire absorbs the heat and maintains the steel temperature below the critical temperature of approximately 400°C. The heat is dissipated by 1) convection to other unexposed elements of the system, and 2) by conversion of the water to steam which is vented. Make-up water can be provided by a simple gravity fed piping system. The concept, however, has only been applied to columns in buildings.

On offshore platforms the system could readily be used for vertical and diagonal tubular members without the need for a major redesign of the structure. The primary objective would be to protect the structure in the vicinity of the wellhead, a limited portion of the structural system for the platform. Figure 6 provides an conceptual drawing of a water filled tubular member system. Discussion of an analytical model for design of water filled members for developing the technology for blowout fires is included in Appendix C.

The development of this concept for protection of structural members against blowout fires has several advantages:

a. Analytical predictions are feasible to determine water replacement rates as a function of heat flux and the size and thickness of steel members [10]. The unknowns associated with external protection with water spray cooling are eliminated since the heat absorption of the water in the enclosed vessel can be calculated.

b. The water filled column system can provide protection for an indefinite period as long as water can be provided to replenish evaporated water.

c. The water filled members are uniformly protected, and combined with a conventional sprinkler/deluge system to protect the deck beams structure, would provide a continuous protection system for the derrick substructure. (There remains a need to investigate the use of the external spraying protection by means of sprinkler/deluge systems.)

The experimental plan include fire tests of small scale tubular columns to verify the predictions of water replacement rates. The small scale test will simulate a column in a derrick substructure which is to a blowout fire. Following the completion of planned modifications to CFR large scale fire test furnace, large scale welded tubular members will be tested, again to a test fire simulating a blowout fire.

The objective of this phase of the project is to develop and demonstrate a viable structural protection technology, including engineering design information. This system will work concurrently with a rapid extinction system and thereby enhance efforts to regain well control.

4.2.3 Derrick Protection

The record of incidents indicates that where the flame envelope extends above the drilling floor, the derrick structure collapsed soon after the fire started. The use of water filled tubular members are not feasible for this structure since it would require a radical change in design. The protection of the derrick structure, therefore, must then be accomplished by cooling the steel with a cooling agent such as water. The approach envisioned will be combined with that used to rapidly extinguish fires originating from a blowout up through the drill pipe, as previously mentioned. The data from these tests, for example, may reveal that although a rapid extinguishment system entrained into the flame (figure 5) may not achieve complete extinguishment, it may reduce the heat transfer to the steel sufficiently to prevent structural collapse.

Although this type of test result would not be successful in terms of the objective to rapidly extinguish the fire; the information would be useful in developing structural steel protection which is important in regaining well control.

5. Summary and Conclusions

Blowout fires on offshore platforms and rigs represent a significant hazard to personnel and equipment. During the period 1973 to the present, nine serious blowout fire incidents occurred in the OCS which resulted in extensive damage to the platforms, and in at least one case the platform was a total loss. The fires generally burned for several hours and in some cases, for several days. Considerable damage was usually sustained by the structure near the wellhead, the derrick substructure and the derrick itself.

The record of blowouts and blowout fires indicates that the majority of incidents were associated with drilling operations. Modern well control measures, particularly during deep water drilling, emphasize the prevention of a subsurface blowout. Therefore, when a kick is sustained, the procedure includes a carefully coordinated shutting-in of the well and the venting of the kick through a choke assembly. As a result, the high pressure gas which has entered the well is brought up to the platform or rig in an effort to safely vent the influx. The well head piping and the choke piping systems on the platform are subjected to high pressure hydrocarbon influxes often exceeding 6000 lb/in^2 under these conditions.

As the record indicates, in the case of a blowout fire the structural steel in the vicinity of the wellhead can be expected to weaken and collapse soon after the ignition. Structural collapse can worsen the situation by causing impact damage to the wellhead and thereby increasing the flow of hydrocarbons, and by creating obstructions to surface capping procedures. Emergency procedures in the OCS during such incidents included the use of support vessels which directed water streams on the platform to prevent total collapse. By the time these vessels were brought to the scene considerable structural damage was already sustained.

An analysis of the blowout fire problem suggests that a blowout fire suppression system which is an integral part of the platform equipment should be considered especially for larger, more condensed platforms now planned for deeper waters and for platforms planned for the Alaskan offshore areas. In these situations it would be impossible to bring in support fire fighting vessels to prevent total loss of the structure, and the possibility of subsequent pollution.

The Center for Fire Research has developed a plan for developing fire suppression technology for blowout fires. The technology development will evolve around a basic goal, to extinguish the fire rapidly and to concurrently maintain structural integrity in the wellhead area thereby, enhancing a more rapid and safer recapping operation and to shorten the downtime of a energy production facility.

The experimental program will therefore focus on three areas:

1) Development of an injection system to extinguish blowout fires originating from the well annulus.

2) Development of an air entrained exterior fire suppression system for a blowout fire originating with flow from the drill pipe.

3) Development of a structural protection system which would insure structural integrity until the fire can be extinguished and the flow of hydrocarbons terminated.

6. References

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APPENDIX A

Summary of Blowout Fire Incidents 1973 - 1980

The information obtained from the USGS records and press releases is summarized as follows:

1. During drilling operations on a fixed platform a gas kick was being circulated out of the well when the choke manifold ruptured apparently due to the jetting action of the gas cut mud. The pressure recorded at the surface prior to the blowout was 2900 lb/in^2. The escaping gas was immediately ignited and the fire was reported burning in the substructure and also was seen burning at a height 60 to 80 ft above the rig floor. The derrick collapsed and the upper and second decks slumped to the cellar deck. In addition, the living quarters on the platform were heavily damaged. Water streams from nozzles on barges, were directed onto the platform to minimize the structural damage.

2. During a work over of a well on a fixed platform a 3/4 inch braided gas hose which was used to inject gas from an adjacent well ruptured. The escaping gas ignited and access to the wellhead to shut off the flow was blocked by the heat. The gas pressure at the hose connection to the gas well was reported at 3200 psi. Control was regained when personnel protected by fog water sprays from fire hoses, gained access to shut master valves to the wells. Subsurface valves eventually stopped the flow in the wells but fires were burning at ruptured guage piping and at valve seals, both of which were believed to have been damaged by the heat of the initial fire. There was no significant damage to the structure in the wellhead area.

3. During start-up operations on a production platform, fire occurred at a relief line when safety controls were bypassed. (Minimal information was available on this incident). The production equipment and piping was extensively damaged during the fire, although there was no apparent structural damage to the platform.

4. While in the process of completing a new well, a blowout occurred on a fixed drilling platform. The well was being flushed with seawater when a packer failed at the bottom of the well. The well was shut in and 7200 psi was recorded at the surface. A leak occurred at a flange on the BOP stack. Eventually the leaking gas was ignited dispite the fact that the area was sprayed with water from barges brought to the scene. During the fire the drilling derrick fell off the platform and the draw works substructure fell to the cellar deck knocking off the blowout preventer stack. As a result of the BOP stack being knocked off, the hydrocarbons flowed straight up from the full open 7 inch casing. The fire was extinguished several days later after heavy mud was circulated into the well. The damage to platform structure above the waterline was extensive.

5. While drilling at a depth of approximately 4200 ft, a blowout occurred on a drilling platform while the drill pipe was being removed from the well. The blowout preventers failed and flow from the annulus blew out the rotary

bushing from rotary table. Drilling mud was blown to the top of the derrick and gas from the well ignited. The flowing well finally bridged over the next day. The drilling equipment on the platform was extensively damaged.

6. During drilling operations on a fixed platform, a blowout occurred when gas forced a reverse flow up the drill pipe back through the mud pumps and tanks. The backflow of high pressure gas caused a relief valve to open in the mud discharge system. Gas from the vent quickly engulfed the platform and was ignited. The fire burned for about a 24 hour period while water spray streams from barges cooled and maintained the structural integrity of the platform. Extensive damage was sustained by the platform especially around mud banks and pumps. The fire went out when apparently a slug of water came up through the drill pipe.

7. A blowout occurred on a jack-up rig during drilling operations when gas escaped from the annulus below the pipe rams. (Further details on the nature of the failure were not available for this report.) The pressure on the choke assembly reached 6,000 psi prior to the failure. Eventually the BOP failed and the flow of mud and gas up the well blew the rotary bushing out of the rotary table. The gas ignited and the derrick collapsed 15 minutes later. The fire resulted in a total loss to the rig, which was valued at $26 million.

8. Failure of a gas riser on a combination drilling and production platform resulted in a fire below the derrick. The fire was attributed to a production riser and not to drilling operations. The substructure below the derrick sustained some damage although the extent of damage was not available for this report. Support vessels responded to the fire and directed water streams on the platform to minimize the damage to the structure.

9. During drilling operations at a relatively shallow depth of 2500 ft a blowout occurred on a combination drilling and production platform. The failure occurred around the annulus of the well on the platform and the subsequent fire damaged the structure around the wellhead. The fire resulted in enough structural damage to cause the drilling derrick to list at a 10° angle. The fire went out when the well bridged over, 17 hours later.

APPENDIX C. ANALYTICAL AND EXPERIMENTAL PLAN WATER FILLED STRUCTURAL MEMBERS

The development of a structural steel protection system incorporating water filled members for offshore platforms can build upon well established design methods for columns in buildings. Since many of the parameters of a blowout fire are not quantified, conservative assumption can be used in analyzing the concept of water filled members. It can be assumed in a blowout fire that the entire surface of the column is exposed to the fire. The following equation can be used to estimate the heat transfer rate to the member through radiation and convection [10]:

$$q = 5.674\ \varepsilon f \left[\left(\frac{T_f}{100}\right)^4 - \left(\frac{T_c}{100}\right)^4 \right] + H\,(T_f - T_c)$$

q = rate of heat transfer to column from fire per square meter of column surface (watts/m^2).

ε = emissivity of radiating area (for a two phase flow hydrocarbon fire an emissivity of 1.0 can be assumed for this calculation).

f = configuration factor for radiation from fire to column.

H = convective heat transfer coefficient between column and surrounding gases.

T_f = absolute temperature of fire, °K.

T_c = absolute temperature of column, °K.

The CFR program plans to use this equation as a basis for calculating the water replacement requirements tubular members, necessary to maintain the steel temperature below a critical level. The temperature of the fire can be assumed to follow the time temperature curve developed by Mobil for petroleum fires [8].

The experimental program will attempt to verify the predictions through fire tests of water filled tubular members. The goal of this phase of the project is to develop a plausible technology with appropriate engineering design criteria for protecting vertical and diagonal tubular members during a blowout fire.

APPENDIX B. ESTIMATES OF WATER FLOW REQUIREMENTS FOR EXTINGUISHING FLOWING HYDROCARBON FIRES

The following estimates were computed to determine the water flow rates necessary to achieve extinguishment by energy extraction (cooling) and by oxygen dilution:

1. To absorb the heat generated by boiling water

$$\dot{f}\ \Delta H_f$$

where

$$\dot{f} = \text{fuel flow rate, gm/sec}$$

$$\Delta H_f = \text{heating value of fuel kilo, Cal/gm}$$

Heat sink of water

$$\dot{w}\ \{10^{-3}\left[T_b - T_a\right] + \Delta H_w + C_p\left[T - T_b\right]\} = \dot{w}\ \Delta H$$

when

$$\dot{w} = \text{water flow rate, gm/sec}$$

$$T_b = 100\ ^\circ C$$

$$T_a = \text{ambient temperature}$$

$$\Delta H_w = \text{latent heat of boiling, kilo cal/gm}$$

$$C_p = \text{specific heat of steam, kilo cal/gm } ^\circ C.$$

A typical value of ΔH_f is 11.6 cal/gm for Heptane ΔH_w = 0.54 kilo cal/gm and C_p = 0.47 x 10^{-3} kilo cal/gm °C. Since $T_b - T_a \approx 80\ ^\circ C$ and $T - T_b \approx 1100$ flaming to 0 quenched we have available

$$\dot{w}\ \{0.080 + 0.540 + 0.517\}$$

$$= \dot{w}\ \{1.14\}$$

This yields, the estimated water to fuel flow rate of:

$$\dot{w}/\dot{f} = \Delta h_f/\Delta H \quad 11.6/1.14 = 10$$

2. A second measure is the steam dilution of air needed to lower the limited oxygen index to the extinction point.

Air required

$$\dot{a} = \dot{f}s$$

where

$\dot{f}$ = fuel flow rate

s = mass of air needed per mass fuel burned

The steam diluted air would be

$$\dot{a} + \dot{w}$$

where

$\dot{w}$ = steam supply rate

If the limiting air dilution is D, then

$$D = \dot{a}/(\dot{a} + \dot{w})$$

$$= \dot{f}s/(\dot{f}s + \dot{w})$$

$$\dot{w} = \dot{f} \left[s(\frac{1}{D} - 1)\right]$$

Typically the limiting oxygen is 14% to 15% for room temperature and D = 2/3 to 5/7.s for Heptane is 3.52 gm O_2 per gram fuel or 15.2 gm air per gram fuel so

$$\dot{w} = \dot{f} \left[15.2(\frac{1}{2})\right] \qquad \dot{f} \left[15.2(\frac{2}{5})\right]$$

$$= 7.6 \qquad 6.08$$

Note:

Both these calculations assume perfect utilization and, for the dilution method, involve the rather imperfectly known required dilution, D. (The above value could be off by a factor of 2!).

A quick look suggests the dilution method is distinctly favored but most of the air entrained by the lower part of the plume must be diluted. This could be six to ten times the air required. In addition the steam would have to be generated, which involves the first method. With the plume entrainment taken into account, the cooling effect seems more likely to succeed unless "lift off" is achieved. In reality both the cooling and dilution mechanisms will be operating simultaneously. In any event, a water flow rate of at least 6 times the fuel flow rate seems needed.

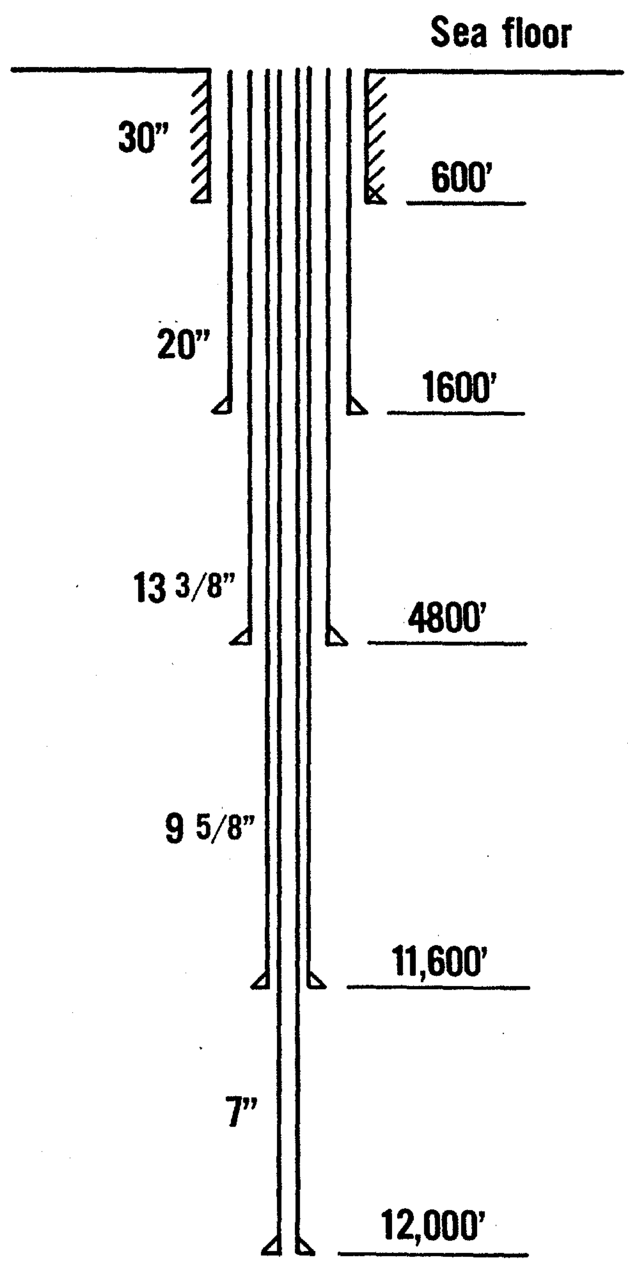


Figure 1. Typical arrangement of wellhead casing

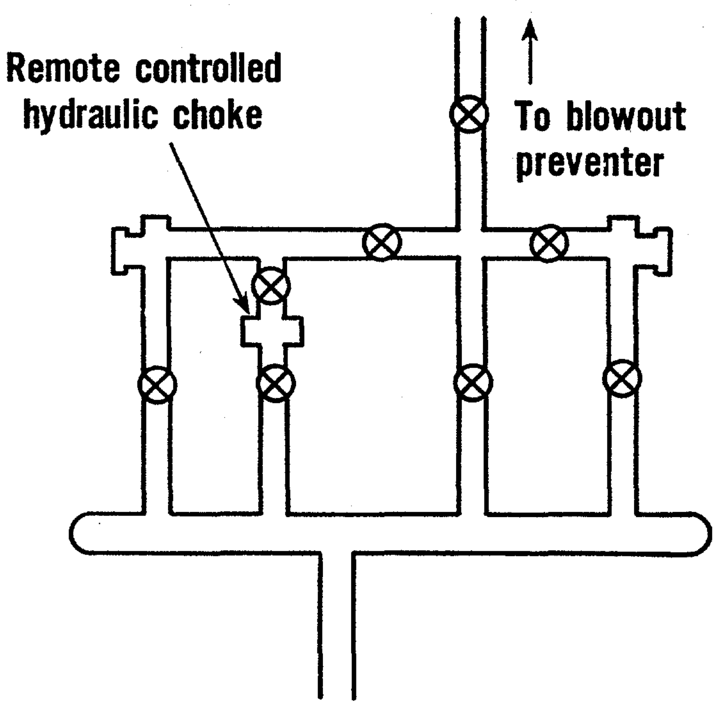


Figure 2. Choke manifold

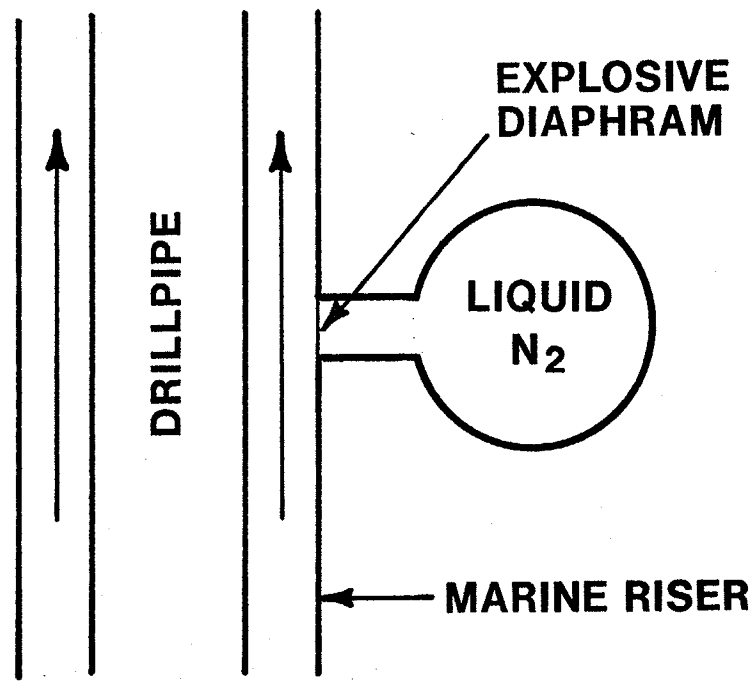


Figure 3. Conceptual fire suppression injection system

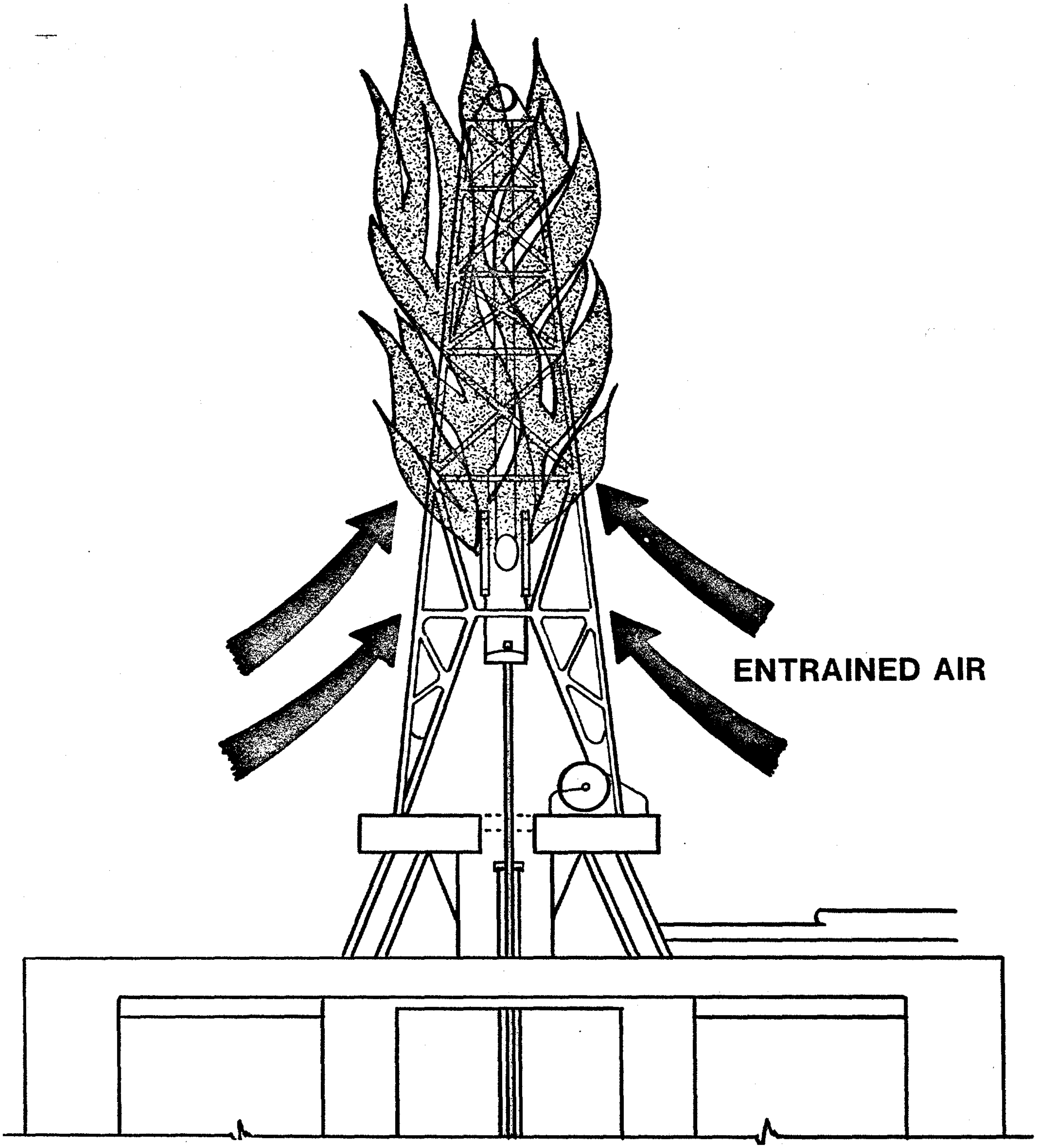


Figure 4. Blowout fire through drill pipe

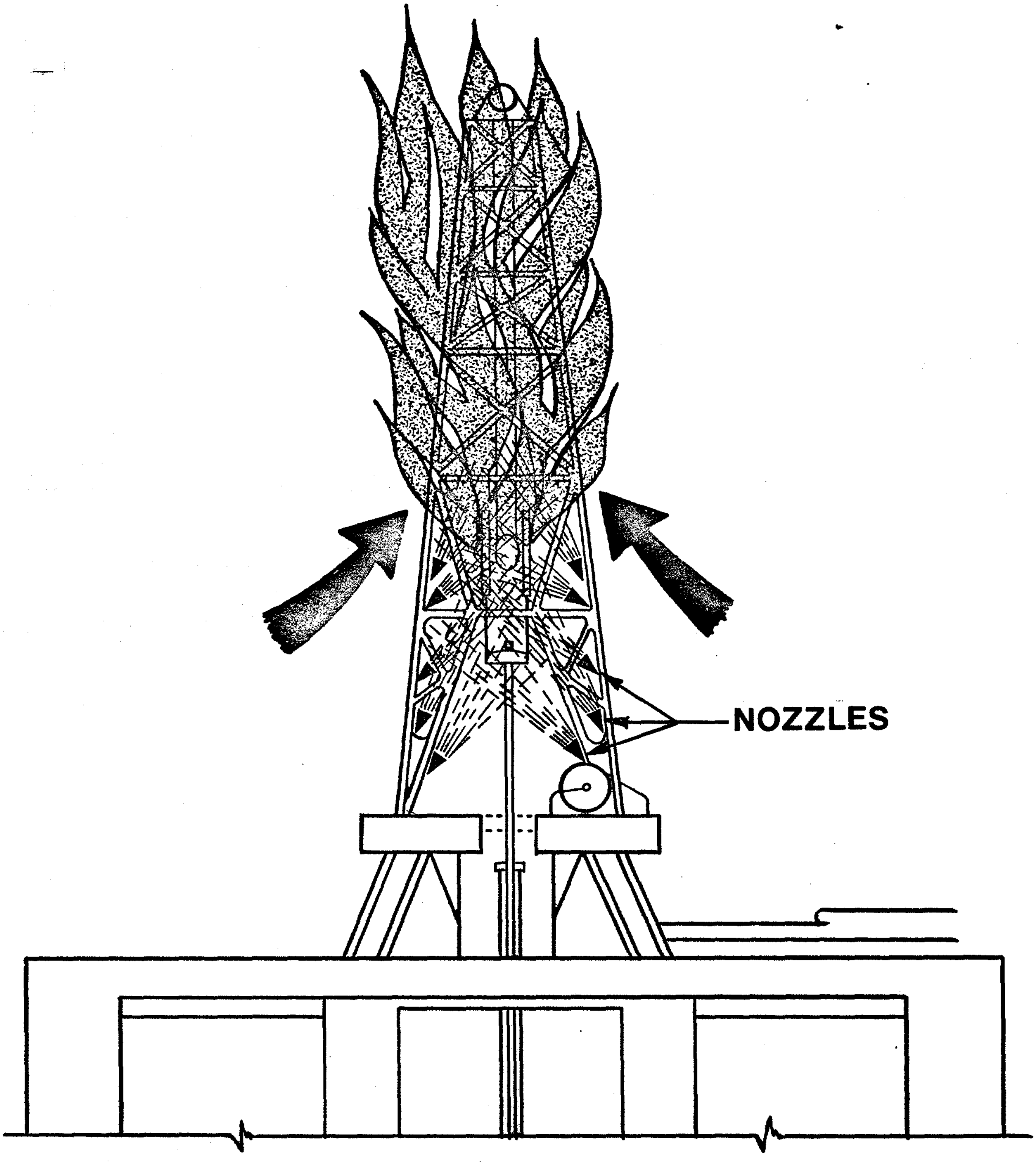
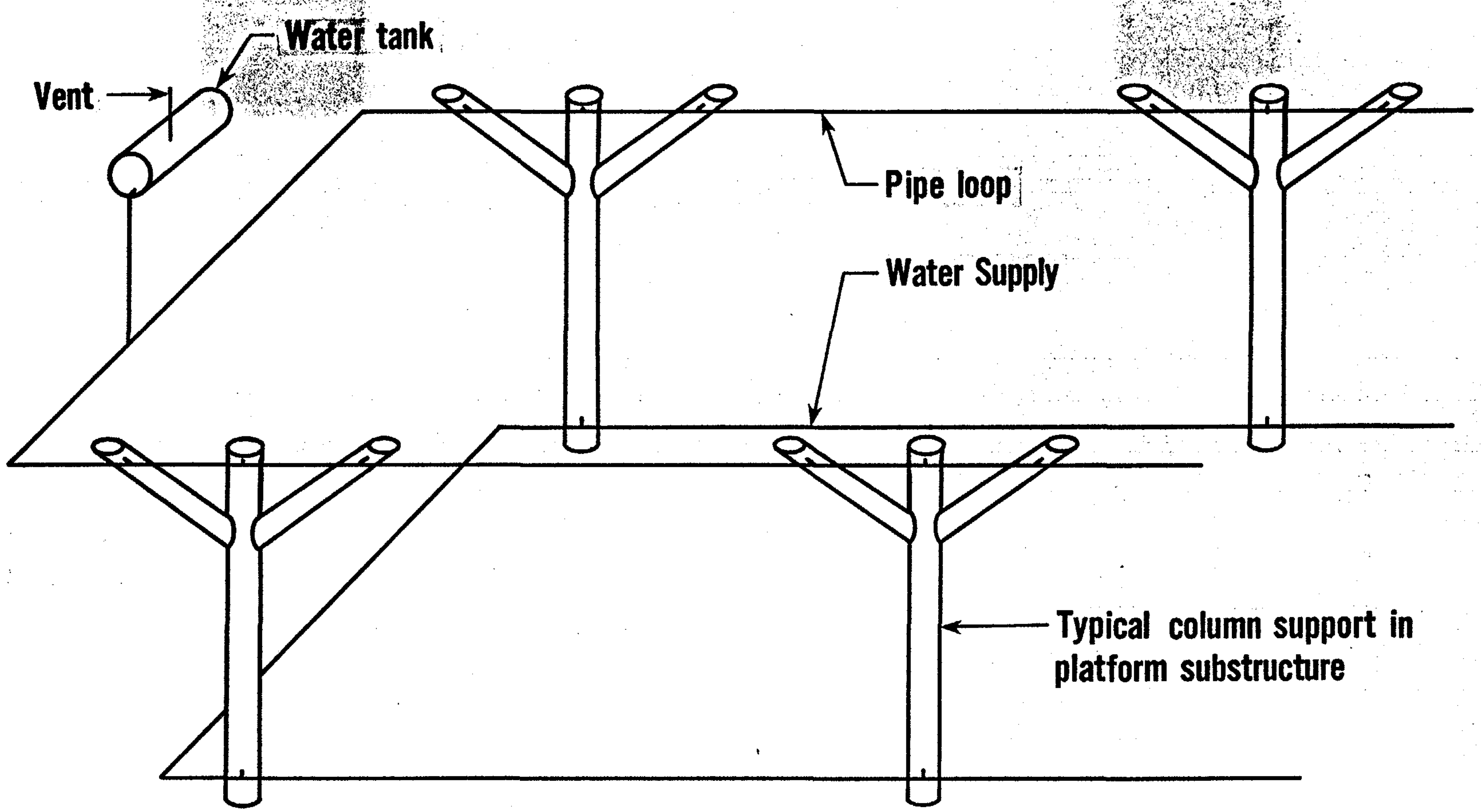


Figure 5. Air entrained fire extinguishing system



CONCEPTUAL DRAWING

WATER FILLED COLUMNS

Figure 6.