Environmental Studies Revolving Funds
Report Number 051
November, 1986

DECISION-MAKING AIDS FOR IGNITING OR EXTINGUISHING WELL BLOWOUTS TO MINIMIZE ENVIRONMENTAL IMPACTS

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SUMMARY

This report is an aid to those responsible for deciding whether or not an oil-well blowout should be ignited or extinguished (if already burning) in order to protect the environment. Simple charts, nomographs and tables are provided to compare the advantages and disadvantages of ignited versus unignited blowouts. Check-lists of key questions to consider during the decision-making process are included.

RESUMÉ

Ce rapport se veut un guide pour ceux qui doivent décider s'il faut enflammer une éruption d'hydrocarbures ou en éteindre une déjà en feu afin de protéger l'environnement. Il contient des graphiques,nomogrammes et tableaux simples comparant les avantages et désavantages des éruptions d'hydrocarbures enflammés et non enflammés. Il présente aussi une liste des questions clés qu'il faut considérer avant de prendre une décision à cet effet.

INTRODUCTION

Blowouts are rare but costly events, especially large offshore oil-well blowouts. Hundreds of millions of dollars can be lost through damage or loss to rig and/or platform, blowout control expenditures, lost hydrocarbons, lost time, environmental damage claims, and cleanup costs, and even damage to corporate image and constraints on future drilling or development programs.

In dealing with a well blowout, one of the major decisions affecting overall cost is whether to ignite or to extinguish the well. Although in many cases the decision is clear and can be made quickly without the need for in-depth analysis, other situations can be more complicated, especially those involving protracted blowouts in environmentally sensitive areas.

The decision to ignite a blowing well would usually be made in the interests of environmental and human health protection. Generally, if the combustion process is highly efficient, potential environmental effects and spill cleanup costs can be virtually eliminated. These benefits, however, may be gained at the expense of preventing the early capping of the well, losing the rig itself, and necessitating a costly and lengthy relief well drilling program. If the combustion process is incomplete or inefficient, then there could be environmental trade-offs associated with the decision: the impacts of a large oil discharge lasting a relatively short period (days) versus a smaller discharge lasting a long period (months).

These are but a few of the numerous considerations when deciding whether or not to ignite (or for that matter extinguish) a blowing well.

The original purpose of this study (ESRF 1984) was to produce a single-page decision-making procedure for ignition of the products of a well blowout. This was found to be impossible since each well blowout is a unique event requiring a different control technique, and the environmental impact associated with each blowout -- the stated reason for considering igniting or extinguishing a well -- is highly site-specific and time-dependent. Any attempt to delineate a procedure to make such a critical decision inevitably ends up balancing the cost of the decision (rig damage, increased well control problems, etc.) against the benefit of the decision (reduced environmental impact). As the environmental impact side of the balance is impossible to predict prior to or even during a blowout the decision cannot be prejudged.

The purpose of this report is threefold: first, to provide the decision-makers with some assistance in determining the situations in which ignition of the well should be considered; second, to provide a check-list of important questions that should be answered before a decision is made; and third, to provide guidance in answering these questions. This approach differs from that of a single-page, decision-making procedure in that it does not lead the decision-maker to a simple "yes" or "no" answer but ensures that the decision-maker has the proper information to assess a unique situation and make an informed, defensible decision.

The basis for this report is a blowout from a well located on Canada lands.[1] The probability of occurrence, the reasons for, and the prevention of blowouts are not subjects of this report. For whatever reason and however unlikely, the starting point of this study is a blowout, defined as an uncontrolled flow of formation fluids to the surface.

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1 "Canada lands" are defined as those regions administered under the Canada Oil and Gas Act (offshore waters or land in the north).

The first section of the report deals with the types and characteristics of blowouts that may occur on Canada lands as a result of petroleum exploration and production. The near-source behaviour of oil, condensate, natural gas, and hydrogen sulphide (H_2S) released from the blowouts is described. The downwind extent of explosion zones, H_2S hazard zones, and the dimensions of oil or condensate slicks are predicted for surface and subsea blowouts over a wide range of flowrates.

The second section of the report describes the effects of igniting the products of the well. Combustion efficiencies for gas, H_2S, oil and condensate, and radiant heat fluxes and secondary effects are predicted for surface and subsea blowouts. Factors that limit the feasibility of ignition (such as water flow) are also discussed.

The third section presents an overview of well control techniques. The implications of igniting the well for well control are discussed.

The fourth section is a review of several actual blowouts and the reasons behind the decisions to ignite/not ignite or to extinguish/not extinguish the wild well. A review of blowout statistics, as they relate to the consequences of well ignition, the time frame of ignition, and the incidence of burning blowouts, is also presented.

The fifth section of the report delineates the key decision-making factors that must be addressed when considering igniting or extinguishing a well blowout.

The final section of the report contains check-lists of the key factors to be reviewed prior to making a decision to ignite or to extinguish a blowing well. Separate check-lists are provided for sour gas, land, offshore-surface, and offshore-subsea blowouts.

The report finishes with a listing of the conclusions of the study.

POTENTIAL BLOWOUTS

The purpose of this section is to provide an overview of the types and characteristics of blowouts, particularly their near-source behaviour. Three blowout sources are considered: from platforms (offshore), from the sea bed, and from land based rigs. Four well products are considered; natural gas, H_2S, crude oil and condensate.

GENERAL DESCRIPTION

In order to illustrate the processes that occur during a blowout, a description of oil-well blowouts follows. The description is equally valid for a condensate-well blowout with the exception that the condensate generally makes up much less of the total flow. The behaviour of a gas or sour gas blowout would be identical except that no liquid would be present.

Oil-well blowouts generally involve two fluids, namely crude oil and natural gas. The volume ratios of these two fluids are a function of the characteristics of the geological reservoir and of the fluids, pressure and temperature. The natural gas, being a compressible fluid under pressure at reservoir conditions, provides the driving force for an uncontrolled blowout. As the well products flow upwards, the gas expands, finally exiting at the well-head at velocities of up to hundreds of metres per second. At this point the oil makes up only a small fraction of the total volumetric flow.

There are several generic types of blowouts: the well-head blowout (where the fluids exit vertically from the well-head through a blowout preventer (BOP), casing string, drill pipe, or tubing), the side blowout (where the fluids escape horizontally from a loose or damaged flange, BOP ram, or bent well-head), the annular or cratering blowout (where back pressure in the well causes the oil to escape past a casing shoe and erupt at the surface around the well-head equipment), and the underground blowout (where the fluid flows into another lower-pressure formation or to the surface through cracks and fissures in the earth's crust).

This report deals primarily with vertical well-head blowouts since:

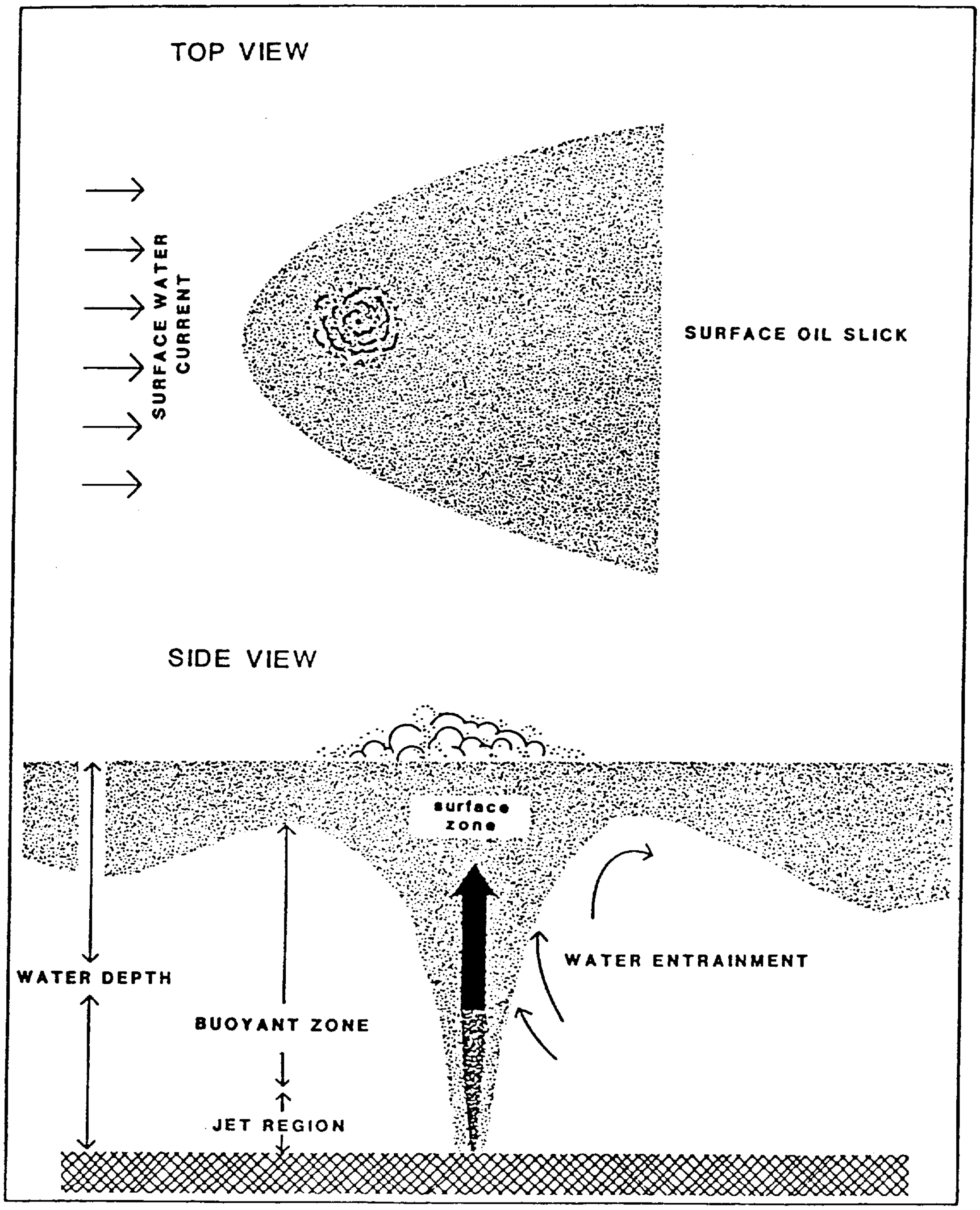
- one of the first actions in a side blowout is to remove the damaged well-head equipment thus converting side blowouts into well-head blowouts;
- annular or cratering blowouts are usually caused by shutting in the blowing well, and reopening the well will likely revert the situation to a well-head blowout; and
- underground blowouts are not amenable to ignition as a countermeasure.

There are three release locations possible for an oil-well blowout: subsea, land (including artificial islands) and offshore platform. As the near-source behaviour of land and offshore platform blowouts are nearly identical they are described together as surface blowouts. Because the behaviour of subsea and surface blowouts is quite different, each is described separately.

Subsea Blowouts

The oil and gas released from a subsea blowout pass through three zones of interest as they move to the sea surface (Figure 1). The high velocity at the well-head exit generates the jet zone which is dominated by the initial momentum of the gas. This highly turbulent zone is responsible for the fragmentation of the oil into droplets ranging from 0.5 to 2.0 mm in diameter (Dickins and Buist 1981). Because water is also entrained in this zone, a rapid loss of momentum occurs a few metres from the discharge location. In the buoyant plume zone, momentum is no longer significant relative to buoyancy which becomes the driving force for the remainder of the plume. In this region the gas continues to expand due to reduced hydrostatic pressures. As

FIGURE 1 SCHEMATIC VIEWS OF A SUB-SEA BLOWOUT



the gas rises, the oil and water in its vicinity are entrained in the flow and carried to the surface.

Although the terminal velocity of a gas bubble in stationary water is only about 0.3 m/s, velocities in the centre of blowout plumes can reach 5 to 10 m/sec due to the pumping effect of the rising gas in the bulk liquid. That is, the water surrounding the upward moving gas is entrained and given an upward velocity, which is then increased as more gas moves through at a relative velocity of 0.3 m/s, and so on. When the plume becomes fully developed a considerable quantity of water is pumped to the surface.

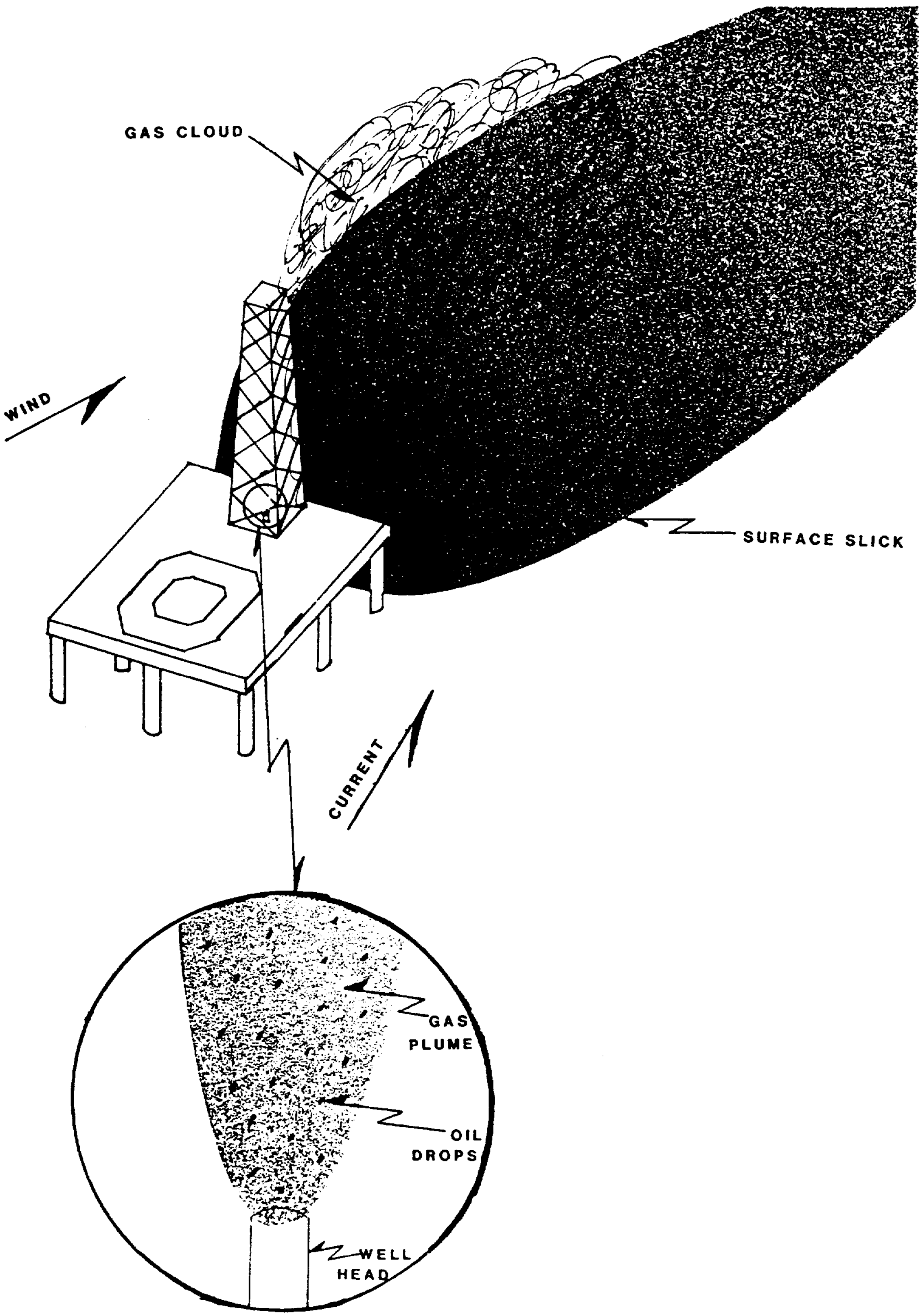
In the surface zone, the rising water and oil flow away from the centre of the plume in a radial layer. At the surface the oil coalesces in this outward flow of water and is spread into a slick at a rate much faster than conventional oil diffusion or spreading rates. The resulting slick takes on a hyperbolic shape when subjected to a natural water current, with its apex pointed up-current (Figure 1).

The sizeable quantities of gas released during these blowouts enter the atmosphere at the 10-15 m diameter turbulent bubble area above the plume and disperse through atmospheric turbulence. This gas could hinder a countermeasures operation since an explosion potential would exist near the gas source. If sour gas is present a significant toxic hazard zone could be generated.

Surface Blowouts

Oil released during a land blowout or from an offshore platform above the water's surface will behave quite differently than that from a subsurface discharge. The gas and oil will exit at a high velocity from the well-head and the oil will be fragmented into a cloud of fine droplets (Figure 2). The height that this cloud rises above the release point will vary depending on the gas velocity, oil particle size distribution, and the prevailing wind velocity. Based

FIGURE 2 SCHEMATIC OF A SURFACE BLOWOUT



on limited data from actual incidents it is reasonable to assume that the cloud will rise to a point about 25 m above the well-head. The fate of the oil and gas at this point is determined by atmospheric dispersion and the settling velocity of the oil particles (Figure 2). The oil will "rain" down, the larger droplets falling closer to the release point. If the gas is blowing through the derrick or some other obstruction the larger oil droplets may agglomerate on the obstruction(s) and flow down onto the rig floor. The gas will disperse in the prevailing wind creating an explosion zone in the vicinity of the rig. Sour gas will create a toxic hazard zone. On land, in low wind conditions, gas and H_2S may accumulate in depressions.

CHARACTERISTICS OF SUBSEA BLOWOUTS

Near-Source Gas Behaviour

Explosion zones. The near-source concentrations of the natural gas released from a subsea blowout have been modelled (see Appendix I for details) for two atmospheric stability classes: D representing a neutral atmosphere and F representing a very stable atmosphere (the worst case). The results, shown in Figure 3, give the downwind extent of the explosion zone (defined as the distance for the gas to dilute below the lower explosive limit of 135 g/m^3) as a function of gas flowrate (10^4 to 10^7 m^3/day) and wind speed (2 to 12 m/s). Under calm conditions the model used to predict the dispersion of the gas is no longer valid. The gas will simply billow up and diffuse away from the turbulent surface zone in all directions. Completely calm conditions are very unusual occurrences offshore.

Sour gas hazard zones. A similar procedure was used to calculate the downwind extent of the hazard zone for releases of H_2S (defined as the distance for the gas to dilute below the threshold limit value (TLV), 0.014 g/m^3). The results shown in Figure 4 (for a 540 g/s or 0.4 m^3/s H_2S release rate) are given for a range of wind speeds (2-12 m/s) and three stability classes. Figure 5 shows similar results for a 2800 g/s (2 m^3/s) H_2S release rate.

FIGURE 3 EXPLOSION ZONE LIMITS

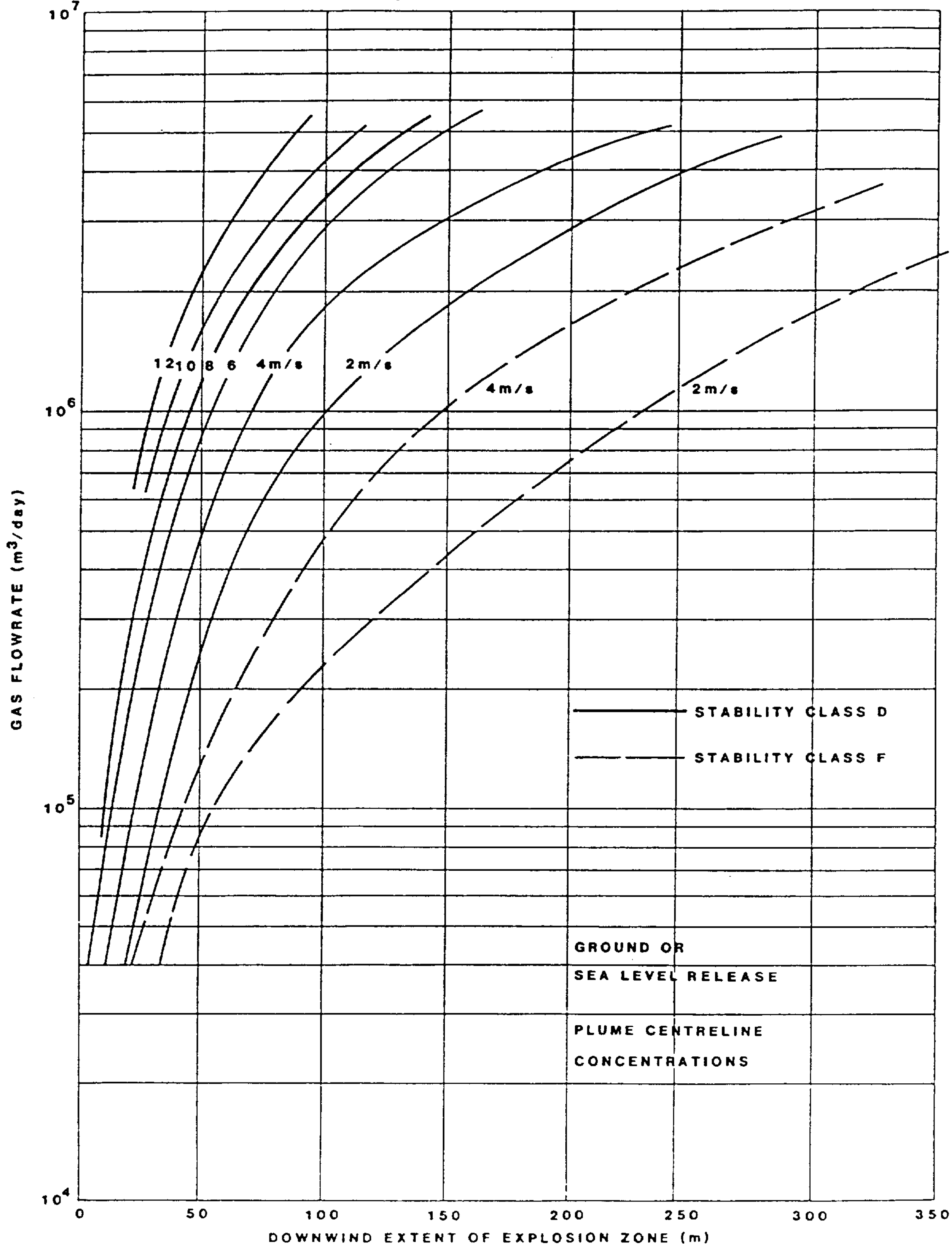


FIGURE 4 H_2S LIMITS (PLUME CENTRELINE CONCENTRATIONS)

540g/s SOURCE ($0.4m^3/s$)

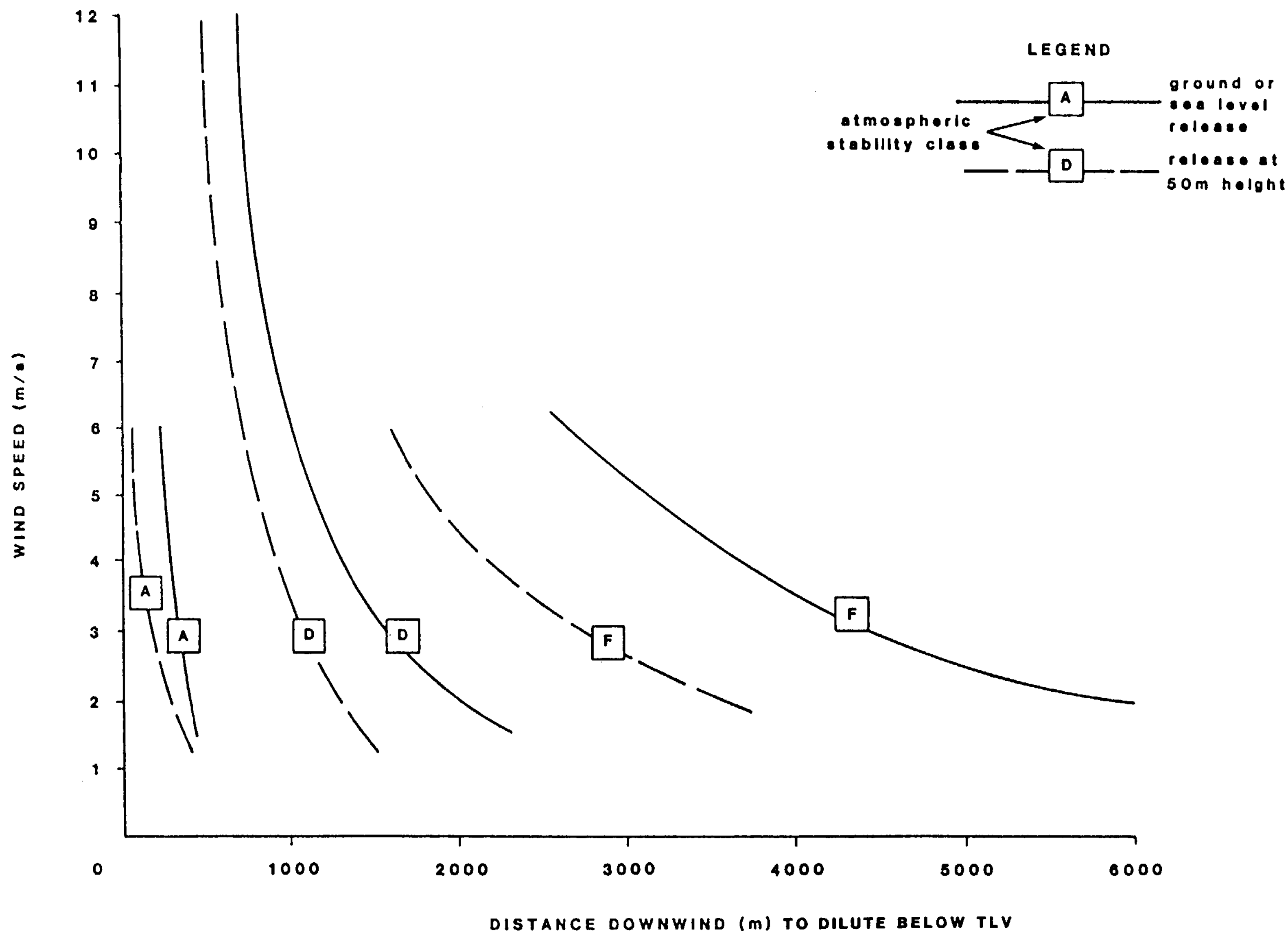
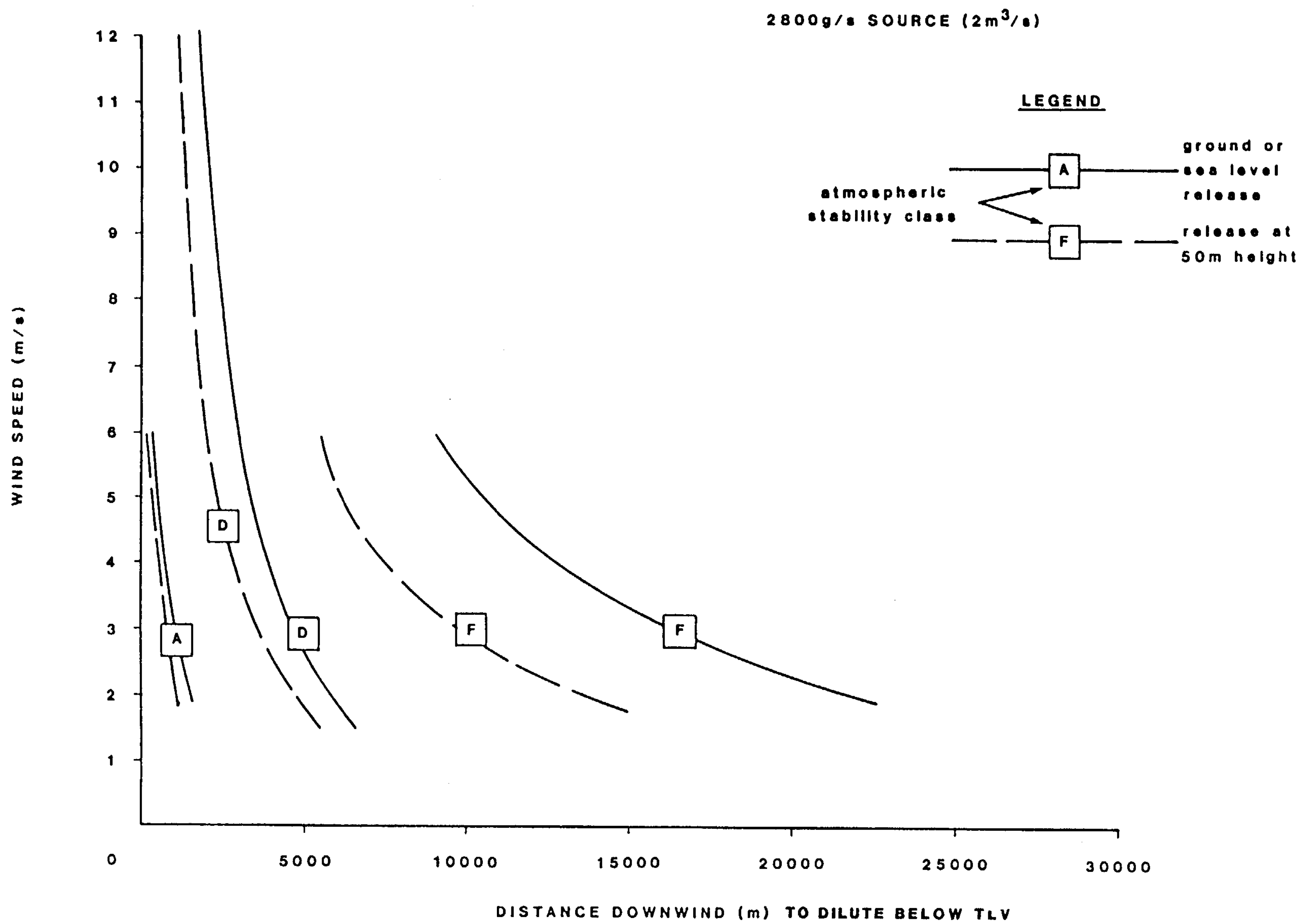


FIGURE 5 H_2S LIMITS (PLUME CENTRELINE CONCENTRATIONS)



Oil and Condensate Slick Dimensions

The dimensions of the slick emanating from a subsea blowout have been estimated using a mathematical model (see Appendix 2 for details). The results are shown in Figure 7 with the dimensions defined in Figure 6. Of prime importance to this study is the slick width (Z) and thickness (X) which, in combination with the oil flowrate, will determine the physical limitations and effectiveness of spill control operations (and thus, in part, the potential environmental impact). It should be noted that oil released from a subsea blowout may entrain water (up to 90% by volume) to form a water-in-oil emulsion, thus increasing the volume of fluid in the surface slick. This phenomenon would only affect the predicted slick thickness, increasing it by up to a factor of ten for a 90% water emulsion. Table 1 shows the predicted slick dimensions for two subsea blowouts involving condensate (36 and 156 m^3/day; 18,000 m^3/m^3 gas-to-oil-ratio (GOR); 20, 80, and 200 m water depth). Comparison with Figure 7 shows that the slick thicknesses are much less for condensate blowouts than for oil-well blowouts.

TABLE 1

PREDICTED SLICK DIMENSIONS FOR SUBSEA CONDENSATE-WELL BLOWOUTS

CONDENSATE FLOWRATE	GOR (m^3/m^3)	WATER DEPTH (m)	R (m)	Y (m)	Z (m)	X (μm)
36	18,000	20	2	165	1040	1.6
		80	8	455	2860	0.6
		200	21	880	5530	0.3
156	18,000	20	2	270	1710	4.4
		80	8	750	4700	1.6
		200	21	1450	9100	0.8

FIGURE 6 DIMENSIONS OF SUBSEA BLOWOUT

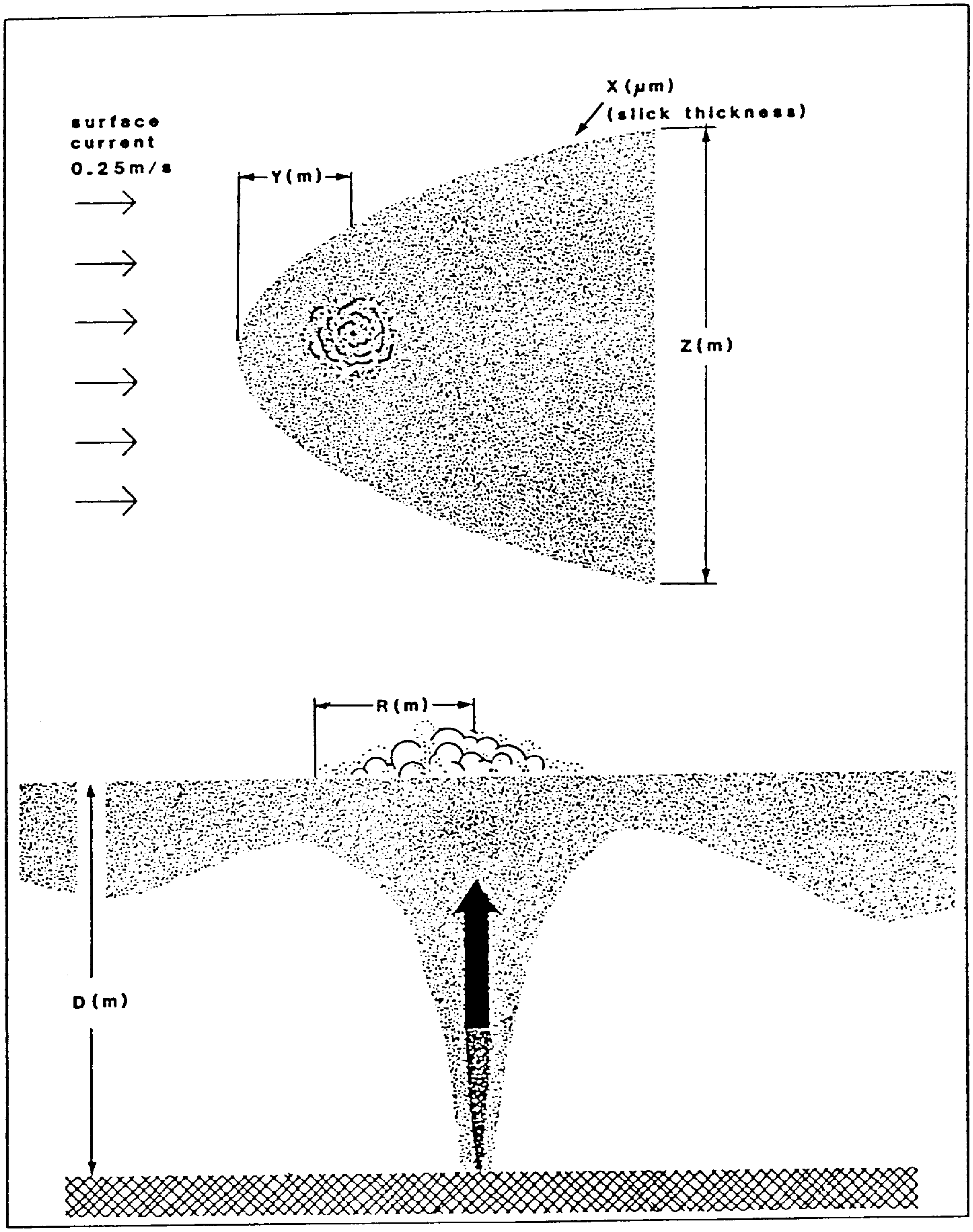
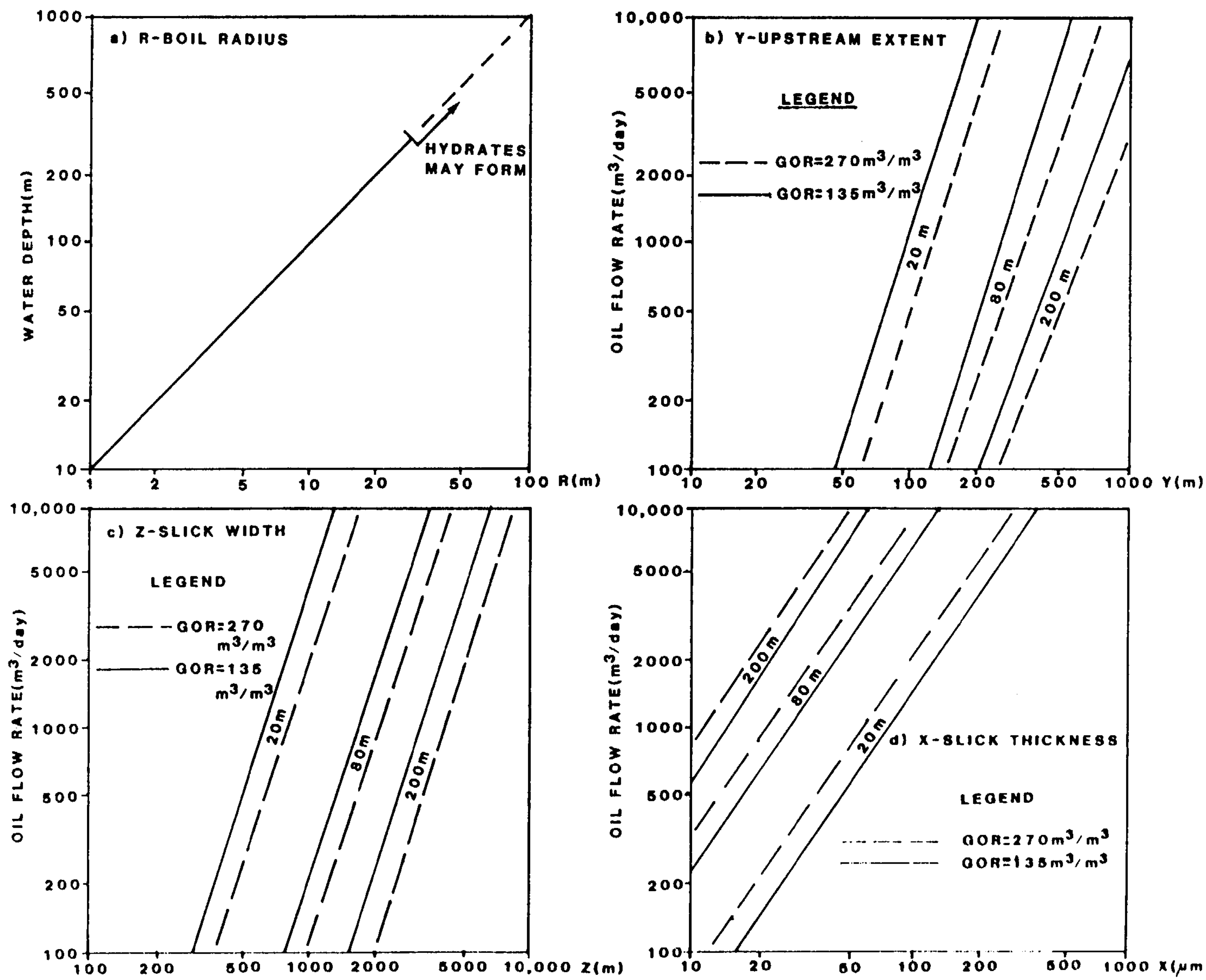


FIGURE 7 PREDICTED SLICK DIMENSIONS: SUBSEA BLOWOUT



CHARACTERISTICS OF SURFACE BLOWOUTS

Near-Source Gas Behaviour

Explosion zones. The dispersion of the natural gas released from an offshore platform blowout has been modelled (see Appendix 1 for details). A release height of 50 m has been assumed (25 m platform height above water and a 25 m plume rise). The extent of the explosion zone is shown in Figure 8 for atmospheric stability class D (neutral) and F (very stable) in wind speeds of 2, 4, 6, 8, 10, and 12 m/s. Comparison of Figures 3 and 8 show that the explosion zones for platform releases are considerably smaller than for subsea releases. For blowouts on land it is best to use the more conservative subsea release curves (Figure 3) since the local topography can affect the dispersion of the gas. Extreme caution should be exercised in estimating explosion zones on land at low wind speeds because, depending on its composition, the natural gas may be denser than air and may accumulate in depressions.

Sour gas hazard zones. The distance for 0.4 and 2.0 m^3/s releases of H_2S to disperse below the TLV are shown in Figures 4 and 5 for a 50 m high release. For more general purposes, and specifically for land wells, the approach adopted by the Alberta Energy Resources Conservation Board (ERCB) is recommended. The radius of the "Emergency Planning Zone" (defined as the 100 ppm limit rather than the TLV of 10 ppm) as a function of H_2S release rate is shown in Figure 9. Extreme caution must be used when applying H_2S dispersion curves to land releases at low wind speeds. Depending on the H_2S content of the gas it may be denser than air and may accumulate in depressions.

FIGURE 8 EXPLOSION ZONE LIMITS - PLATFORM BLOWOUT

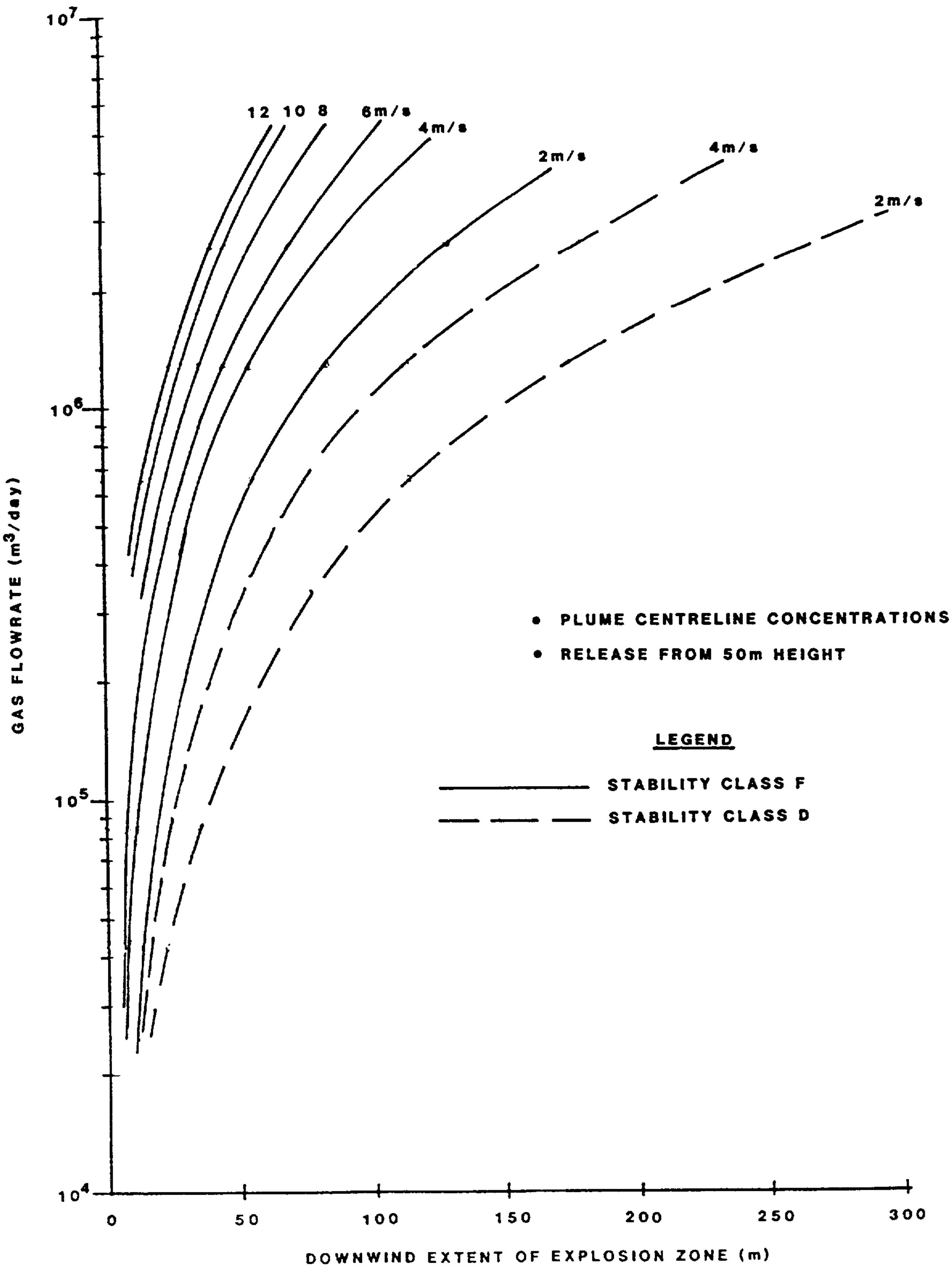
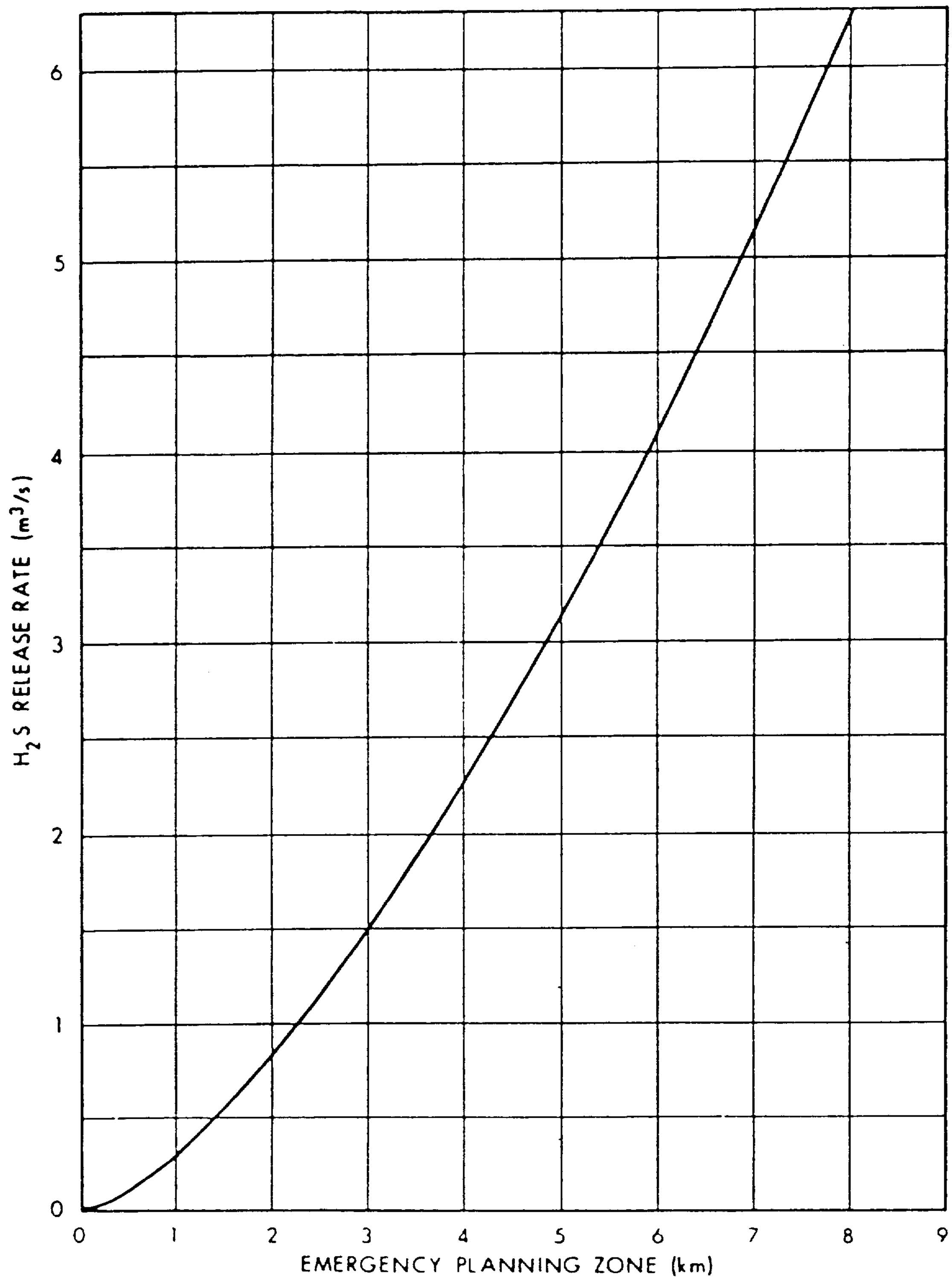


FIGURE 9
EMERGENCY PLANNING ZONES FOR SOUR GAS WELLS



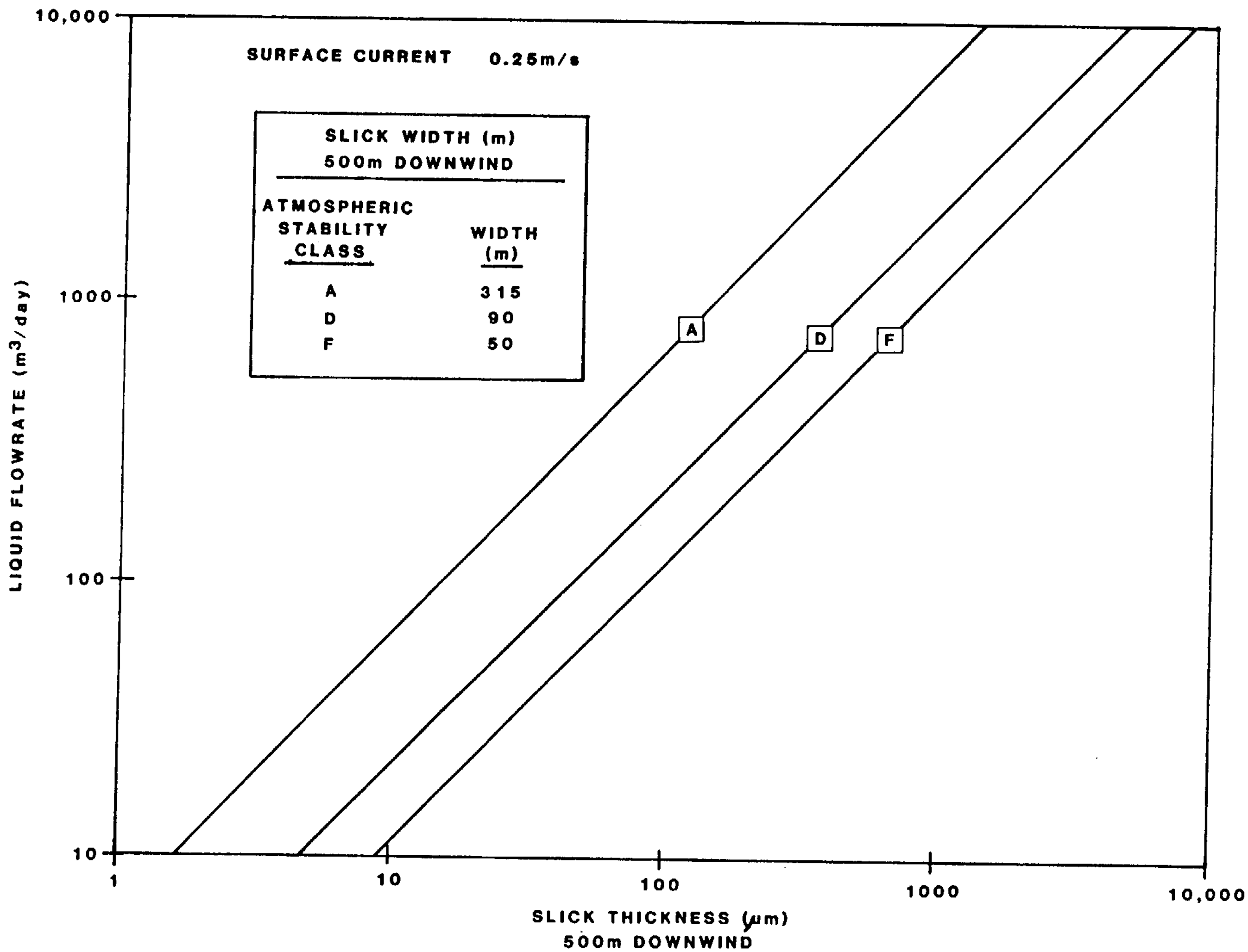
Source:ERCB, 1984

Oil and Condensate Slick Dimensions

The width and thickness (500 m downwind) of slicks of oil and condensate "raining" out of the plume from a platform blowout have been modelled (see Appendix 2 for details). The results are shown on Figure 10. It should be noted that as a first approximation, the width of the slick is not a function of flowrate, just of the lateral atmospheric dispersion coefficient (i.e., stability class). Comparison of Figure 10 with Figure 7 shows that slicks resulting from a platform or surface blowout are much thicker and narrower than slicks from subsea blowouts (and thus are easier to control and recover using conventional spill cleanup equipment).

For land blowouts the oil or condensate will rain from the gas plume to collect on the ground. This surface oil will pool, soak into the surrounding soil or snow and, if enough accumulates, flow towards lower-lying areas.

FIGURE 10 OIL AND CONDENSATE SLICK DIMENSIONS - SURFACE BLOWOUT



SUMMARY

Subsea blowouts can result in very wide, thin slicks of oil or condensate on the water surface. The potential explosion zones are relatively small (several hundred metres at most), except in the event of no wind in which case the explosion zone is unpredictable. Hazard zones from hydrogen sulphide can extend for considerable distances (several kilometres) downwind.

Platform blowouts generate much narrower, thicker slicks than do subsea blowouts. Both explosion zones and H_2S hazard zones are smaller for platform blowouts than for subsea blowouts because of the release height above the water surface.

Oil and condensate from a land blowout will accumulate around the site until the area is saturated. The liquids will then flow to low-lying areas. The explosion and H_2S hazard zones for a land blowout will be similar to those for a platform blowout except in the case of low wind speed where dense gas may accumulate in depressions to an unpredictable extent.

COMBUSTION EFFICIENCIES AND SECONDARY EFFECTS

In this section the efficiency of burning oil, condensate, gas and H_2S in a blowout plume is estimated. Secondary effects of igniting the well products (radiated heat fluxes, combustion products, etc.) are also predicted. Factors that may limit ignition (water or sand production, choked flow from the well, etc.) are covered.

As with the previous section the discussion is limited to blowouts involving a vertical unobstructed flow from the well-head. Platform and land blowouts are discussed separately from subsea blowouts.

The results of this section are presented in the form of simple charts and nomographs that can be used to quickly estimate the potential combustion efficiency and secondary effects for igniting a wide range of blowout situations.

SURFACE BLOWOUTS

Oil and Condensate

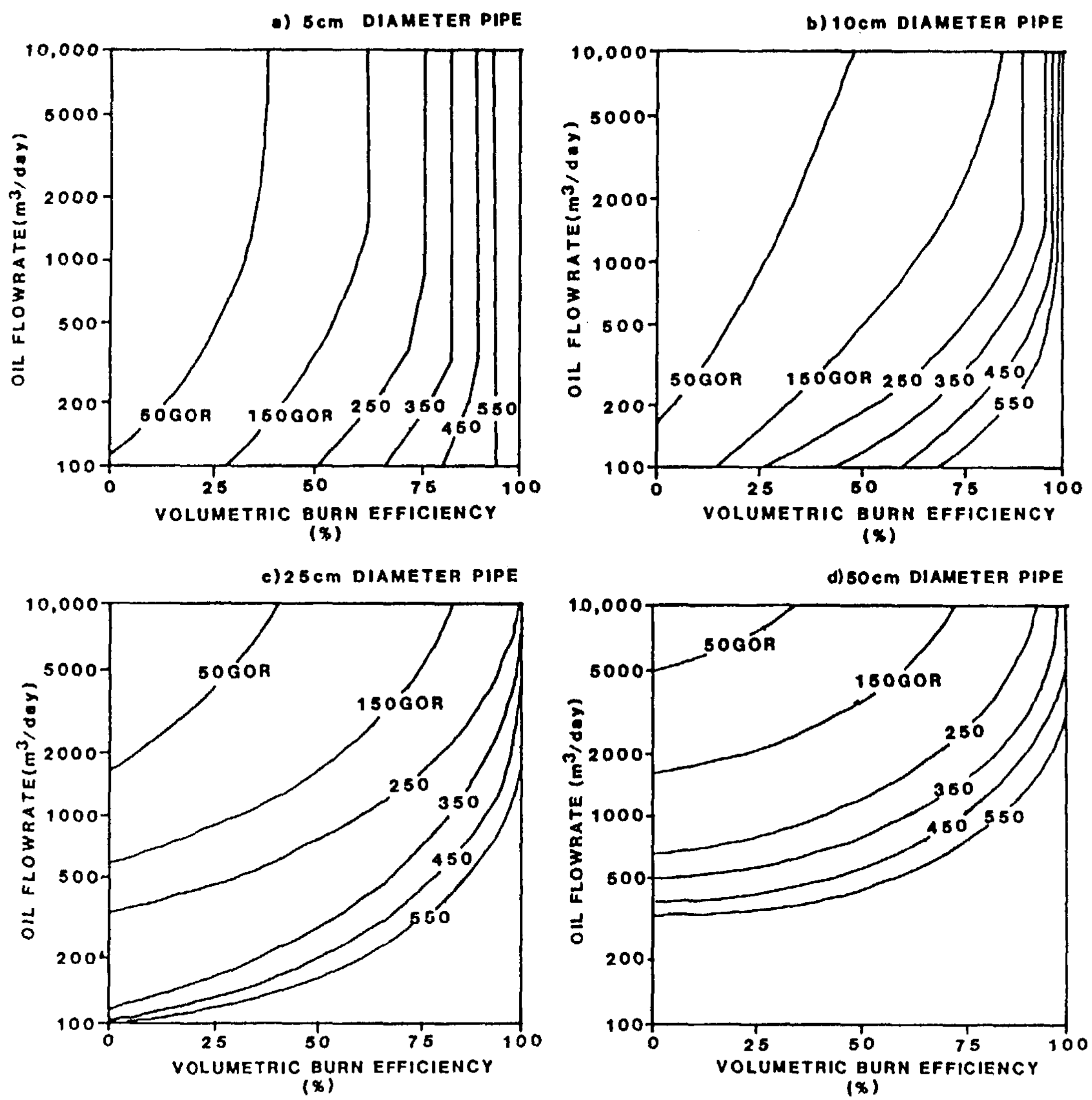
The removal efficiency of burning liquid hydrocarbons was modelled mathematically by predicting the size of an oil or condensate droplet that would vaporize completely as it travelled through the burning gas plume and comparing this with the predicted droplet size distribution produced by atomization of the liquid at the well-head. The details of the model may be found in Appendix 3.

The results of the model are shown in Figure 11 for oil blowouts. Nomographs of oil flowrate (100 to 10,000 m^3/day) versus predicted burn efficiency (defined as the percentage of the volume of oil released that is burned) for six GOR's (50, 150, 250, 350, 450, and 550 m^3/m^3) are given for four representative orifice diameters. It should be noted that the predicted results are conservative since they account only for the oil burned in the gas fire and do not include additional burning as the oil droplets fall from the plume. In addition, the model results are based on flow through a smooth pipe; a constriction in the pipe (such as partially closed rams) will serve to improve atomization and thus combustion efficiency. The model only applies to ripple and annular two-phase flow conditions. Well-head conditions which result in froth, slug, or bubble flow are arbitrarily assigned a burn efficiency of zero. Condensate blowout combustion efficiencies are inevitably 100%, by virtue of the very high GOR's involved.

Concentrations of water in the burning oil droplets of up to 30 % by volume have no detrimental effects on combustion efficiencies and, in fact, may improve the efficiency and reduce soot emissions (Energetex 1981). However, water contents of between 30 and 60 % by volume have an adverse effect on combustion because viscous water-in-oil emulsions are produced which are resistant to atomization. Such emulsions exhibit progressivly lower combustion efficiencies with increasing water content. Emulsions with water content in excess of 60% by volume will not burn (Westergaard 1981a). It should be noted that the above discussion relates to well-mixed flows of oil and water. Discrete slugs of water will quickly extinguish a burning well.

Produced sand, being an inert substance (unlike water which absorbs considerable heat in vaporizing), is unlikely to affect combustion efficiencies dramatically. In fact, the use of flares to burn off diesel-based drill muds with high solids contents is being investigated (Swiss and Wotherspoon 1986).

FIGURE 11 SURFACE BLOWOUT OIL COMBUSTION EFFICIENCY



Gaseous Products

<u>Natural gas</u>. Ignition of the natural gas from a blowing well will result in complete combustion of the gas. At exit velocities (at the well-head) in excess of about 20 to 30 % of sonic velocity (517 m/s in methane at 20°C) the flame will "lift-off" the well-head but efficient combustion will still take place.

The presence of produced water in the gas will not extinguish the flame unless the water content exceeds about 5% by volume of the gas flow (Energetex 1981). Discrete slugs of water will, however, quickly extinguish the burning gas (Westergaard 1981a). The percentage of produced sand required to cool and extinguish a gas flare is unknown, but is probably much higher than the equivalent percentage of water.

<u>Sour gas</u>. No data are available on the combustion efficiency of H_2S in turbulent gas flames; however, as flares of sour gas are common in refineries and gas plants it is likely that the combustion efficiency is very high. The purpose of igniting a sour gas well blowout is twofold: first to provide additional bouyancy to the plume and thereby to lift the combustion products higher into the atmosphere thus reducing ground level concentrations and promoting dispersion, and second, to convert the lethal H_2S to less deleterious SO_2 via the combustion process.

Table 2 illustrates the effect of igniting a 245,000 m^3/day gas well blowout. For this example igniting the blowout results in a thirtyfold increase in plume rise in stability class A conditions and a tenfold increase in class F conditions. The combination of the plume rise and combustion reduces ground level, plume centreline concentrations by a factor of 350 in class A conditions and 1300 in class F conditions (Appendix 4). Sulphur dioxide concentrations produced by igniting the well are several orders of magnitude below the TLV of 5 mg/m^3 (2 ppm), due to the enhanced plume rise.

TABLE 2

<u>EFFECT OF IGNITING A SOUR GAS WELL</u>

(245,000 m^3/day through a 20 cm pipe in a 1.4m/s wind)

VOLUME % H_2S IN GAS	COLD JET RISE (m)		IGNITED JET RISE (m) 1000 m downwind		UNIGNITED + DOWNWIND CONCENTRATIONS OF H_2S (mg/m^3)		IGNITED *+ DOWNWIND CONCENTRATIONS OF H_2S (mg/m^3)		OF SO_2 (mg/m^3)	
	STABILITY CLASS A	STABILITY CLASS F	STABILITY CLASS A	STABILITY CLASS F	STABILITY CLASS A	STABILITY CLASS F	STABILITY CLASS A	STABILITY CLASS F	STABILITY CLASS A	STABILITY CLASS F
13	39	19	985	214	1.4	104	0.004	0	0.08	0
70	39	19	911	195	7.6	560	0.036	0	0.72	0

\+ groundlevel, plume centreline, 1000 m downwind

* assuming 95% conversion of H_2S to SO_2

Secondary Effects

Heat. The major features of a burning blowout are heat and flame. Figure 12 shows the predicted flame lengths of ignited vertical blowouts as a function of oil flowrate for various GOR's. Details of the model used to develop these curves may be found in Appendix 5. The curves were developed on the basis of no wind and thus represent the maximum flame length. Wind will bend the flame over and shorten it.

Figure 13 shows the minimum safe distance from the well for human activity as a function of oil flowrate and GOR. Details of the model used to generate these curves may also be found in Appendix 5. The curves represent the minimum distance from the flame centre (not the well-head) at which a human can work comfortably for an indefinite period of time on a clear, sunny day. The presence of clouds or night-time will allow closer approach. Personnel can move closer to the flame for short periods and stay longer if protective clothing is worn. Directly beneath the flame a "cool" zone exists where, because of the low viewing angle of the flame and the cooling effect of air being drawn into the fire, heat levels are reduced.

Objects inside the safe distance radius from the flame centre will become extremely hot due to the heat radiated from the flame. Thus, although it may be possible to approach the flame for short periods of time equipment, debris, and the surrounding area will be too hot to handle. In fact, the ignition of a blowing well usually results in severe damage to the rig and platform or, in some cases, complete destruction (Offshore Rig Data Services 1983; Manadrill et al. 1985).

Combustion products. The products of combustion of natural gas are CO_2, H_2O, and NO_x. If H_2S is present, SO_x will also be generated. For oil and condensate wells inefficient combustion may result in the generation of soot and a "rain" of burning oil droplets from the end of the flame.

FIGURE 12 FLAME LENGTH FOR SURFACE BLOWOUTS

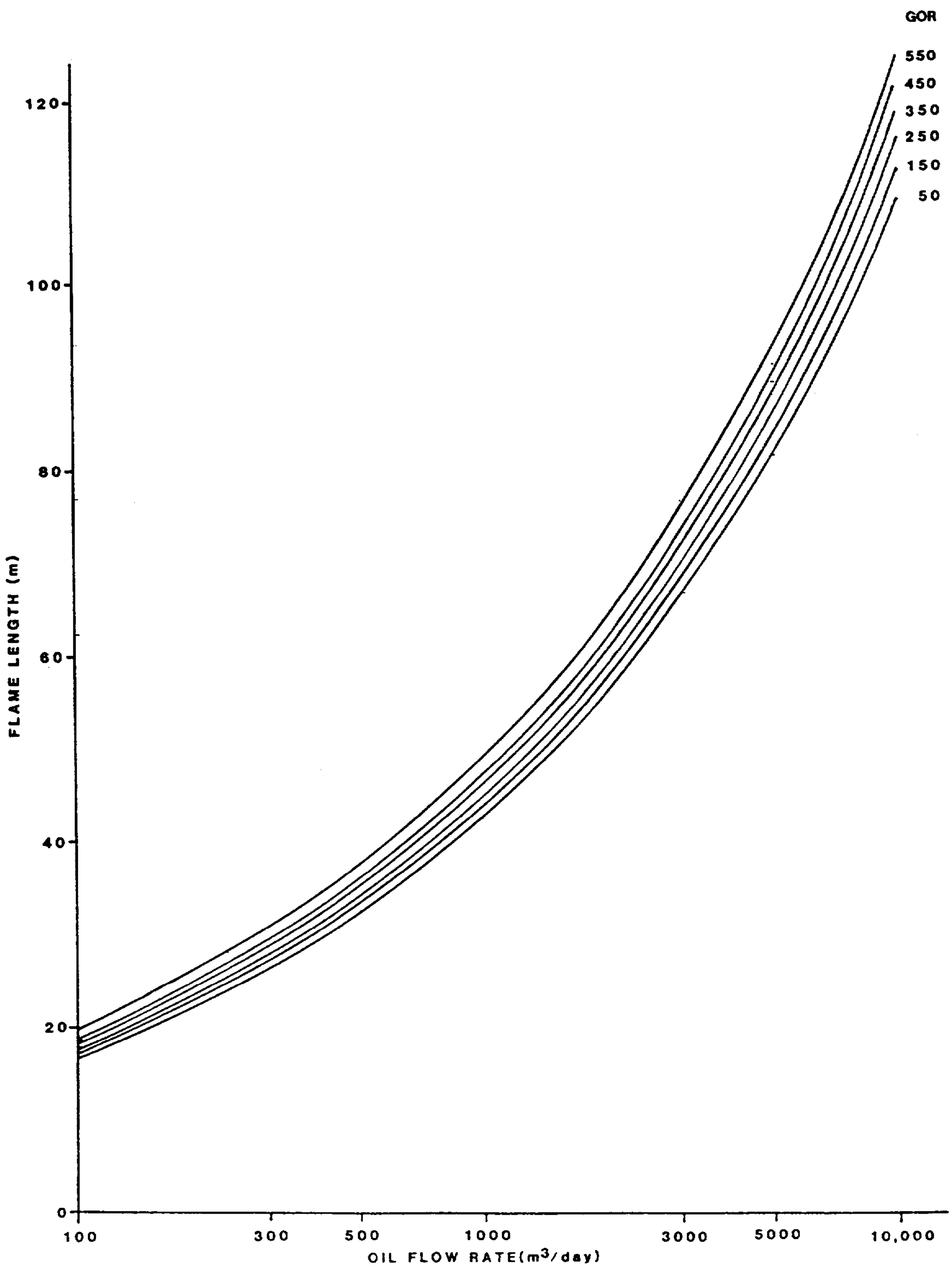
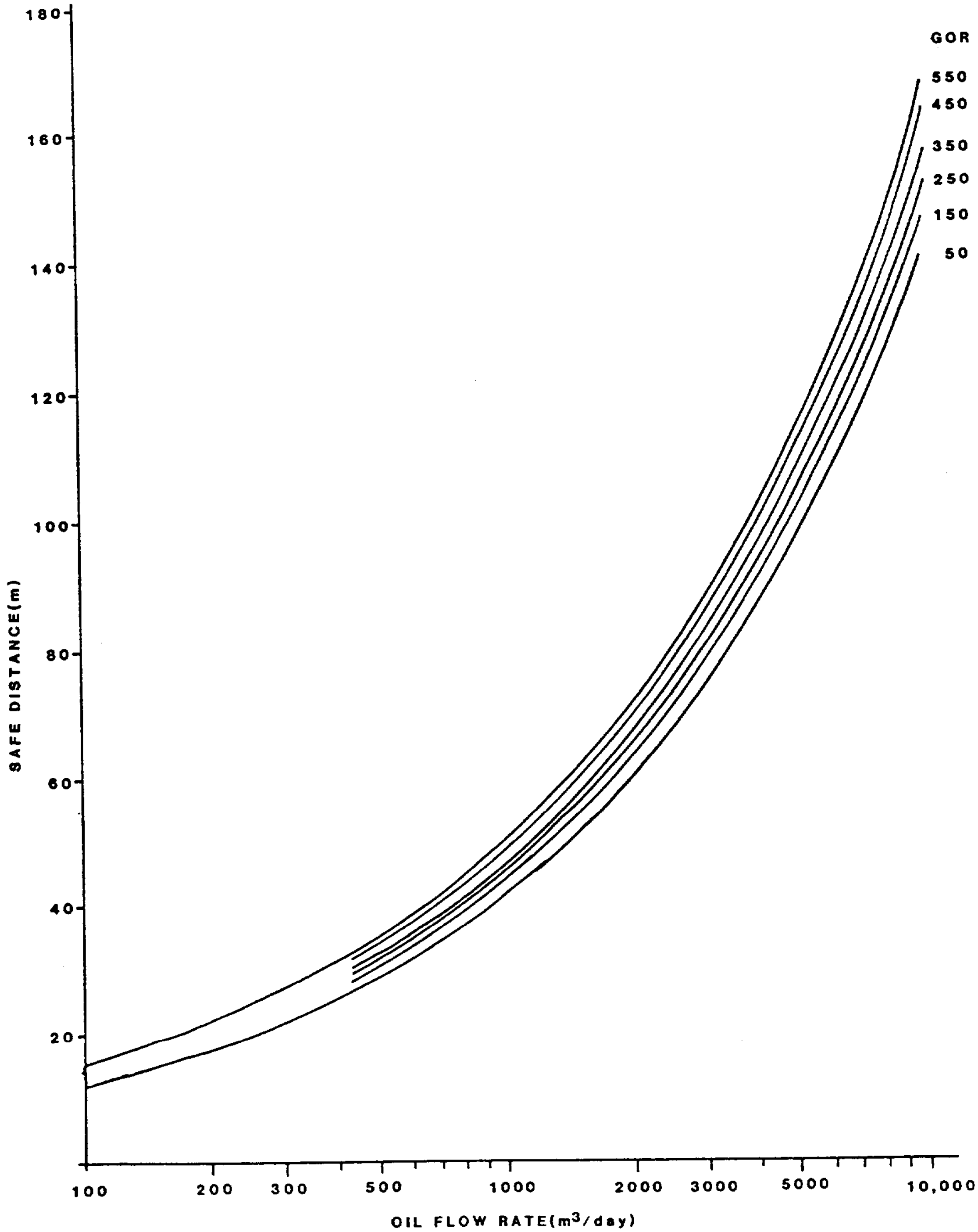


FIGURE 13 SAFE DISTANCE FROM AN IGNITED SURFACE BLOWOUT



SUBSEA BLOWOUTS

Oil and Condensate

As the oil or condensate droplets approach the water surface from a subsea blowout most are drawn outwardly from the gas plume by the induced water flow. As such, only a small fraction of the oil is ejected, in droplet form, into the gas flame above the gas plume. It is unlikely that sufficient heat is radiated from the gas flame to ignite the surrounding oil slick, however, tests done on the Ixtoc-l blowout (Ross et al. 1979) indicate that the radiated heat may result in the flashing of the light ends of the oil.

Gaseous Products

Natural gas. Based on earlier work on gas burning from subsea blowouts (APOA 1977) the minimum flowrate of gas required to sustain combustion at the sea surface can be estimated from:

$$Q_{min} = 12d$$

where Q_{min} = minimum gas flow rate (m^3/day @STP)

d = water depth (m)

Even for water depths of 300 m it is obvious that only a very small gas flow rate is required to sustain combustion at the surface. Because of the low exit velocities of the gas from the water, the flame is likely to be laminar and will burn in a clean, smokeless manner.

Sour gas. As with the surface blowout, no data are available on the combustion efficiency of H_2S in laminar diffusion flames. It is likely to be high, converting all the H_2S to SO_2.

Limiting factors. Although no data are available, earlier modelling work (APOA 1977) indicates that high seas and winds less than 13 m/s will not extinguish the gas flame. Such was the case at the Ixtoc-1 blowout. Ice floes of at least several times the diameter of the boil zone will not extinguish the fire. Larger floes which interrupt the gas flow will, however, extinguish the flames. The burning of the gas will be unaffected by the nature of the fluid flow in the well and/or the presence of produced water or sand.

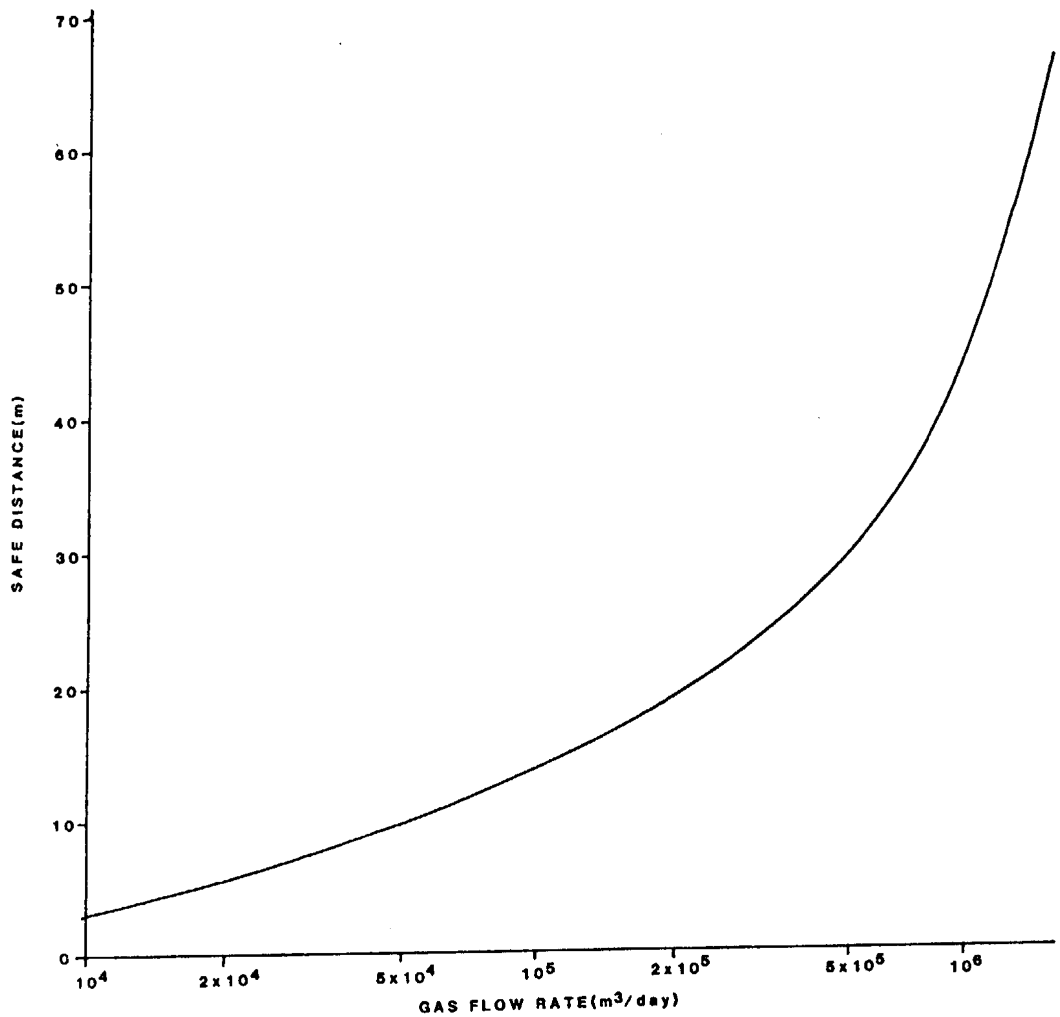
Secondary Effects

Heat. Figure 14 shows the minimum safe approach distance for human activity as a function of gas flowrate (as the oil is not likely to burn, it plays no role). Details of the model may be found in Appendix 5.

Combustion products. As the gas flame is a laminar diffusion flame it will be clean and smokeless. The combustion products will be CO_2, H_2O, and NO_x. If H_2S is present it will burn to SO_2, which will rise and disperse. If oil or condensate is involved small amounts of soot may be generated as small amounts of liquid hydrocarbon are ejected into the gas fire.

Emulsification. One drawback of igniting a subsea oil-well blowout is that the heat radiated from the flame in combination with the intense surface turbulence may promote the formation of viscous water-in-oil emulsions. This phenomenon occurred at Ixtoc-1 (Ross et al. 1979) and has been investigated recently (S.L. Ross 1984). Preliminary results suggest that heat from a burning subsea blowout contributes strongly to the emulsification process.

FIGURE 14 SAFE DISTANCE FROM AN IGNITED SUBSEA BLOWOUT



SUMMARY

The ignition of a blowing surface well can eliminate oil or condensate pollution and explosion hazards as well as reduce the hazards of sour gas. The heat generated, however, is sufficient to prevent easy access to the well-head and renders nearby equipment too hot to handle. Severe damage to, or complete loss of the rig is likely in the event of a fire.

The ignition of the gas rising to the surface from a subsea blowout will eliminate explosion hazards and reduce the hazards of sour gas. The ignition of a significant amount of oil by the burning gas is unlikely; at best the light ends of the oil may be flashed off. It is possible that the radiated heat in combination with the intense turbulence at the surface will promote the formation of water-in-oil emulsions.

WELL CONTROL

The purpose of this section is to review the techniques used to control and kill blowouts. Particular emphasis is placed on the implications of igniting the blowout on the timing and feasibility of controlling the well.

WELL-HEAD TECHNIQUES

Generally, the fastest and most effective technique for controlling a blowing well involves shutting off the flow at the well-head by some means. The well-head control techniques presently in use can be divided into three categories: diverting (allowing the well products to flow to a safe location to reduce well-head pressure while capping or pumping operations are underway), capping (installing and/or closing the well-head with a valve), and mud pumping (stabbing a pipe into the blowing well and pumping mud to balance the pressure). Each of these operations is usually applied, at one time or another, to achieve final control of a blowing well.

Diverting

Diverting, or piping the flow of oil and/or gas away from the well-head to where it can be safely discharged or collected, is a normal kick control procedure. In the event of a blowout, diverting can be used to reduce well-head pressures and to preserve the integrity of weak formations and the casing. The capability of this technique is limited, however, by the diameter and length of the choke line (sonic flow conditions restrict the flowrate of well products) and in the event of a high flowrate blowout, surface pressures may build to failure levels regardless of diversion efforts . Produced sand in the well flow will rapidly erode fittings, particularly bends and constrictions in the flowline, resulting in eventual failure of the diverter system.

In general, the diverted flow is sent to a flare system for burning; however, high flowrates of gas and oil can overwhelm production flare capacities, resulting in the need to cold flare (release any liquids overboard) or unacceptably high back pressures. Many well control experts have recommended the installation of a special spool (for land rigs) or a rig-mounted, annular preventer and diverter system (for Mobile Offshore Drilling Units - MODU's) each of which would incorporate a large-diameter (about 25 cm) diverter pipe leading to a flare a safe distance away (Adair 1979; Adams 1980; Westergaard 1981b). The problems of maintaining operational pressure integrity of the well-head, sand erosion, high-volume flaring, and positioning of a large diameter pipe on a rig must be thoroughly addressed before such recommendations are implemented. A related technique, whereby a longitudinally-hinged, long, large-diameter pipe is placed vertically above a blowing well and the well products ignited at the pipe exit, is used in the USSR to permit safe access to the well-head on land wells.

Capping

Capping a blowing well can involve simply closing a well-head valve or BOP or it can entail the clearing of debris caused by a fire, shooting off damaged well-head equipment, and installing an improvised shut-in device. About 35% of all attempts at well control operations succeed with capping operations.

Surface blowouts. Capping a surface blowout usually involves installing a flanged valve on the blowing well, or stabbing and packing a valved pipe into the well, then closing the valve. The technique does not work for cratering or underground blowouts, and capping a blowing well may convert a surface blowout into a cratering or underground blowout unless the operation is quickly followed by mud pumping.

The presence of a fire at the well severely hampers a capping operation. Debris from heat-induced structural failure of the rig must be removed, equipment becomes too hot to handle, and working conditions become unbearable. Ignition of a blowing well means, at the least, lengthy delays in successfully capping the well.

Techniques related to capping include the Brown Oil Tools crimp and hot tap technique for production-well blowouts and the use of cryogenics to freeze a plug of oil in the well (Anonymous 1970; Westergaard 1981c).

Subsea blowouts. Capping a subsea blowout is extremely difficult unless the BOP is intact and operable. If debris clearance is necessary, well-head equipment needs removal or repair, or it is necessary to expose casing, the operation becomes extremely difficult. Divers who must carry out the operations will be severely hampered because of poor visibility and the currents induced by the gas plume. Relief-well drilling may be the only viable control technique for subsea blowouts.

Pumping Mud

More than half of all successful well control efforts involved only pumping mud or other control materials into the blowing well. In all cases of well blowouts final control is achieved by balancing the pressures in the well with mud and cement.

There are two basic techniques for pumping mud into a blowing well: stabbing a pipe into the well-head and snubbing or stripping it in, then pumping mud until the pressures are balanced; or, pumping mud into the well using the kill line. The well control fluid can be introduced in two ways, bullheading, which involves pumping into a shut-in well against the pressure, or the annular kill technique, which involves pumping either into the drill pipe at a high rate and allowing the mud to rise up the annulus until the friction losses balance the pressures and mud fills the annulus (common practice in kick control), or pumping through the kill line and allowing the mud to fall to the bottom of the well as well products are bled off through the choke line.

Ignition of the well has the same severe implications for mud pumping as it does for capping: destruction of equipment, debris and severe working conditions. Fire will likely prolong, if not prevent, well control operations involving pumping mud.

A related technique involves the injection of heavy balls into the well to increase frictional pressure drop, reduce flows and permit capping (Westergaard 1981c).

RELIEF-WELL DRILLING

Relief-well drilling is the well control technique of last resort, though it may be the only option for subsea, cratering, or underground blowouts. Relief wells take considerably more time to achieve control of a well than do well-head control techniques (180 days average for relief wells offshore [Manadrill et al. 1985] versus 5 days average for surface techniques [Gulf Canada 1981]).

The principle of relief-well drilling is to drill a hole to intersect the blowing well, then to pump water or mud into the well until the formation pressures are balanced. Two basic techniques exist to achieve this. The first involves drilling a relief well to intercept the bottom of the blowing well, establishing communication with the blowing well by fracturing the intervening formation, then flooding the formation and filling the well from the bottom with water or mud. The alternative is called the dynamic kill method in which the blowing well is intercepted just below the bottom of the casing, the intervening formation is fractured and water is pumped at a high rate into the blowing well. The presence of the water increases the frictional pressure drop in the blowing well, causing the flowrate to drop until fluid from the relief well drops to the bottom of the blowing well, filling it and balancing the pressures.

Fire has little or no effect on relief-well drilling operations, since the relief well rigs are usually situated a considerable distance from the blowing well (at about 25% of the planned intersection depth with the blowing well). In fact, relief-well operations are common on blowouts involving fires that preclude well-head control operations (50 to 60% on land, 50 to 70% offshore [Manadrill et al. 1985]). For subsea blowouts, igniting the gas is advantageous in that it eliminates explosion hazards for surface vessel operations.

SUMMARY

The vast majority of well control operations involve well-head procedures. In no surface blowout case is the ignition of the blowing well advantageous since the presence of fire severely hampers and prolongs the control effort. Only in the case of subsea blowout could ignition of the blowout be advantageous, permitting closer and safer relief-well drilling operations.

HISTORICAL REVIEW

In this section blowout statistics are analysed to assess the consequence of a blowout catching fire (deliberately or accidentally), to determine the statistical distribution of blowout durations, and to review cleanup and damage costs. Several case histories where a decision was made either to ignite/leave burning or to not ignite/extinguish blowouts are also presented. Although the probability of a blowout occurring is low, the intent of this study is to provide aids to decision-makers after a blowout has started. As such, no discussion of blowout occurrence statistics is presented. Excellent reviews of the subject may be found elsewhere (Westergaard 1980; Gulf Canada 1981; Manadrill et al. 1985)

CONSEQUENCES OF BLOWOUTS

Probability of Ignition

In order to assess the cost of igniting a well blowout for environmental or safety reasons, blowout statistics comparing ignited versus unignited wells were analysed. About 25% of all blowouts in the U.S. Gulf of Mexico Outer Continental Shelf have resulted in ignition of the well products (Gulf Canada 1981). In Alberta, 50% of all blowouts from 1974 to 1983 resulted in explosions and/or fires. In all the cases where the blowout ignited, the rig and the auxilliary equipment was severely damaged or destroyed (Manadrill et al. 1985).

Rig Damage Costs

A recent study of accidents involving MODU's (Offshore Rig Data Services 1983) indicated that, of those blowouts that damaged a rig, 50% involved fires. The average damage cost was U.S. $13.5 million if the blowout involved fire compared with U.S. $7.3 million if no fire occurred.

This comparison, though convincing, does not represent the entire picture. In the 17 cases in which no fire occurred during a blowout, eight involved damages of less than U.S. $0.5 million, and six of those were of negligible cost. Six total losses were recorded. In the 17 cases in which the blowout ignited, in only two cases was the damage less than U.S $0.5 million and 13 total losses were recorded.

Although similar studies of damage estimates are not available for land-based drilling, it seems reasonable to assume that the trend is the same as for that offshore: damage to rigs and ancillary equipment is far greater if the blowout catches fire.

Blowout Duration

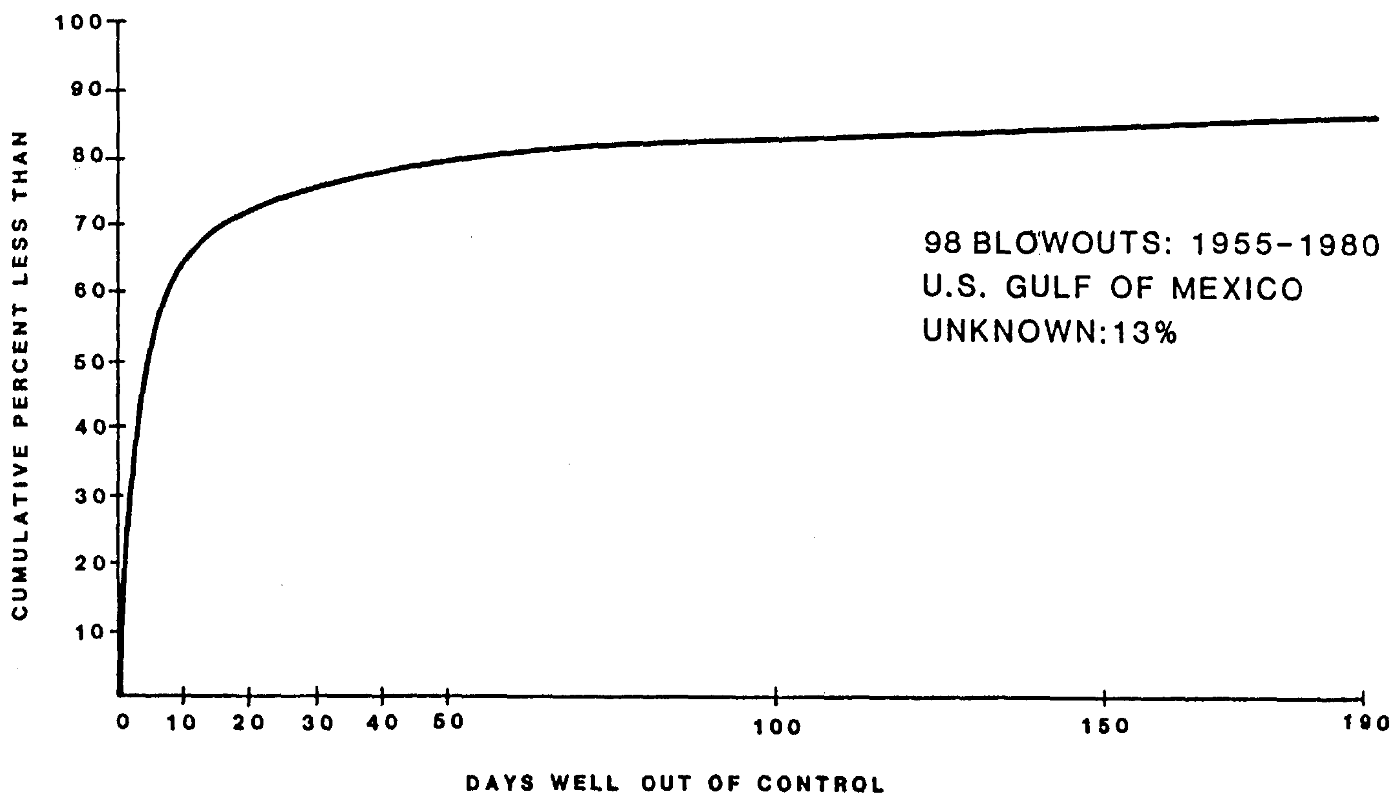
Figure 15 (adapted from Gulf Canada 1981) shows the distribution of blowout durations in the U.S. Gulf of Mexico from 1955 to 1980. Almost 75 % of all blowouts ceased naturally or were killed in less than 15 days. On the other hand, when the blowout lasted longer than 15 days, it generally continued for one or more months and required a relief well. Similar statistics for land wells are not readily available.

Spill Cleanup Costs

A recent analysis of world-wide offshore oil spill cleanup and damage costs (S.L. Ross 1985) is summarized to provide a guide on potential spill-related costs.

Figure 16 shows the relationship between offshore cleanup costs (excluding shoreline and nearshore cleanup costs) as a function of spill volume. Figure 17 shows the cost of shoreline and nearshore cleanup operations as a function of the length of beach oiled. Figure 18 shows the spill damage costs (environmental, socio-economic and litigation) as a function of spill volume. All three figures are based on historical information.

FIGURE 15 PROBABLE DURATIONS OF BLOWOUTS



ADAPTED FROM GULF CANADA, 1981

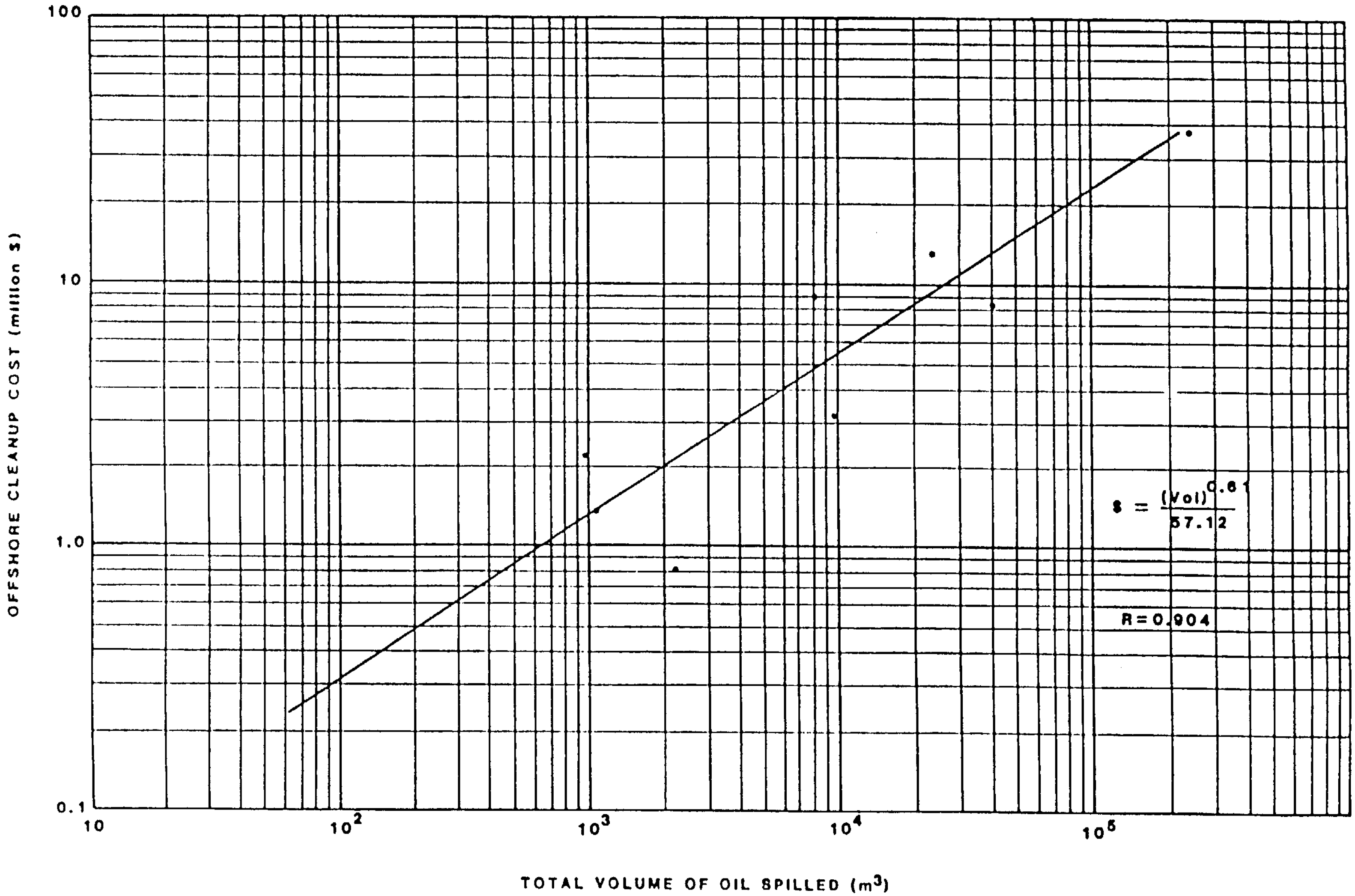


FIGURE 16 COST OF OFFSHORE CLEANUP VS. TOTAL VOLUME OF OIL SPILLED

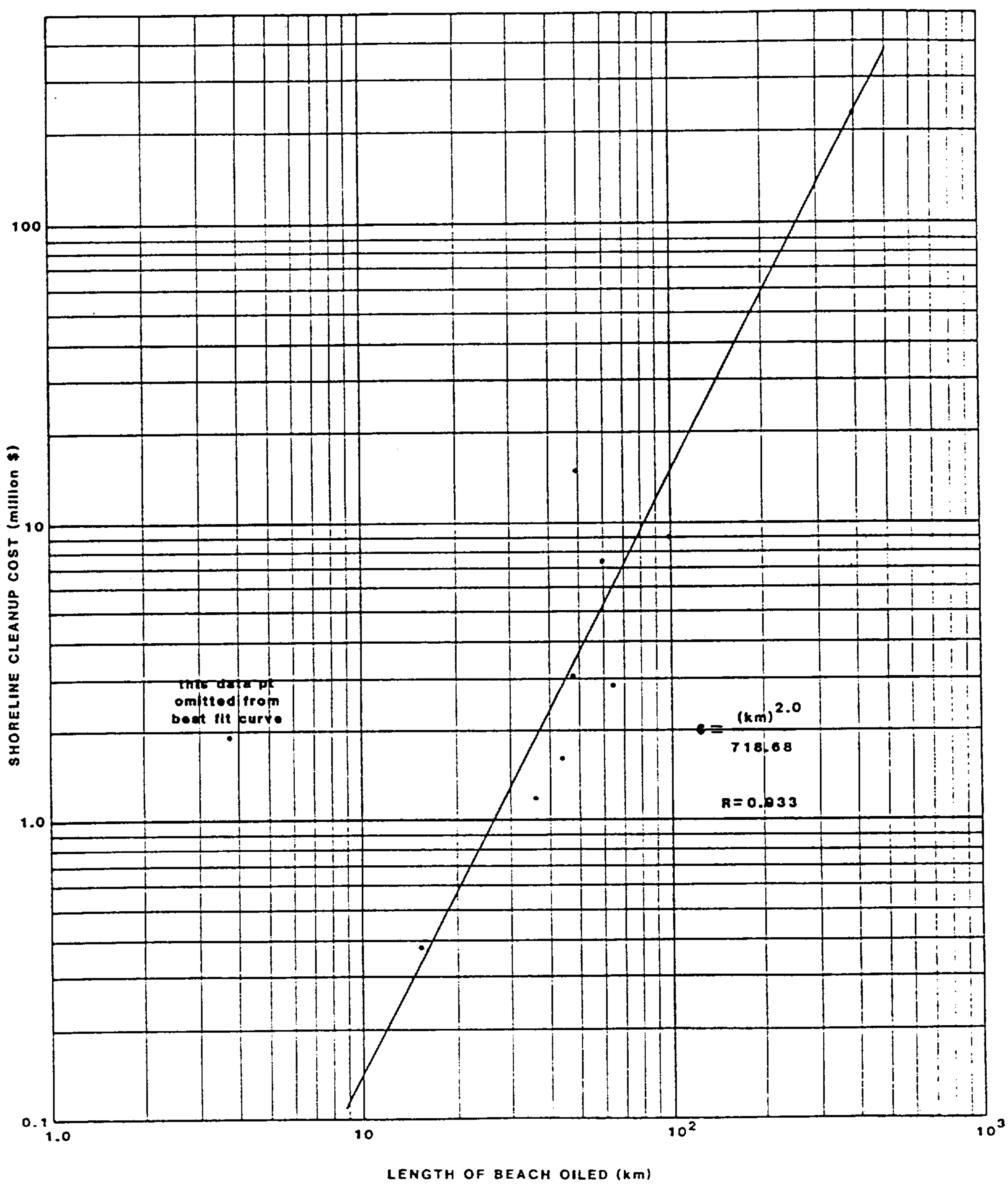


FIGURE 17 SHORELINE CLEANUP COST VS. LENGTH OF BEACH OILED

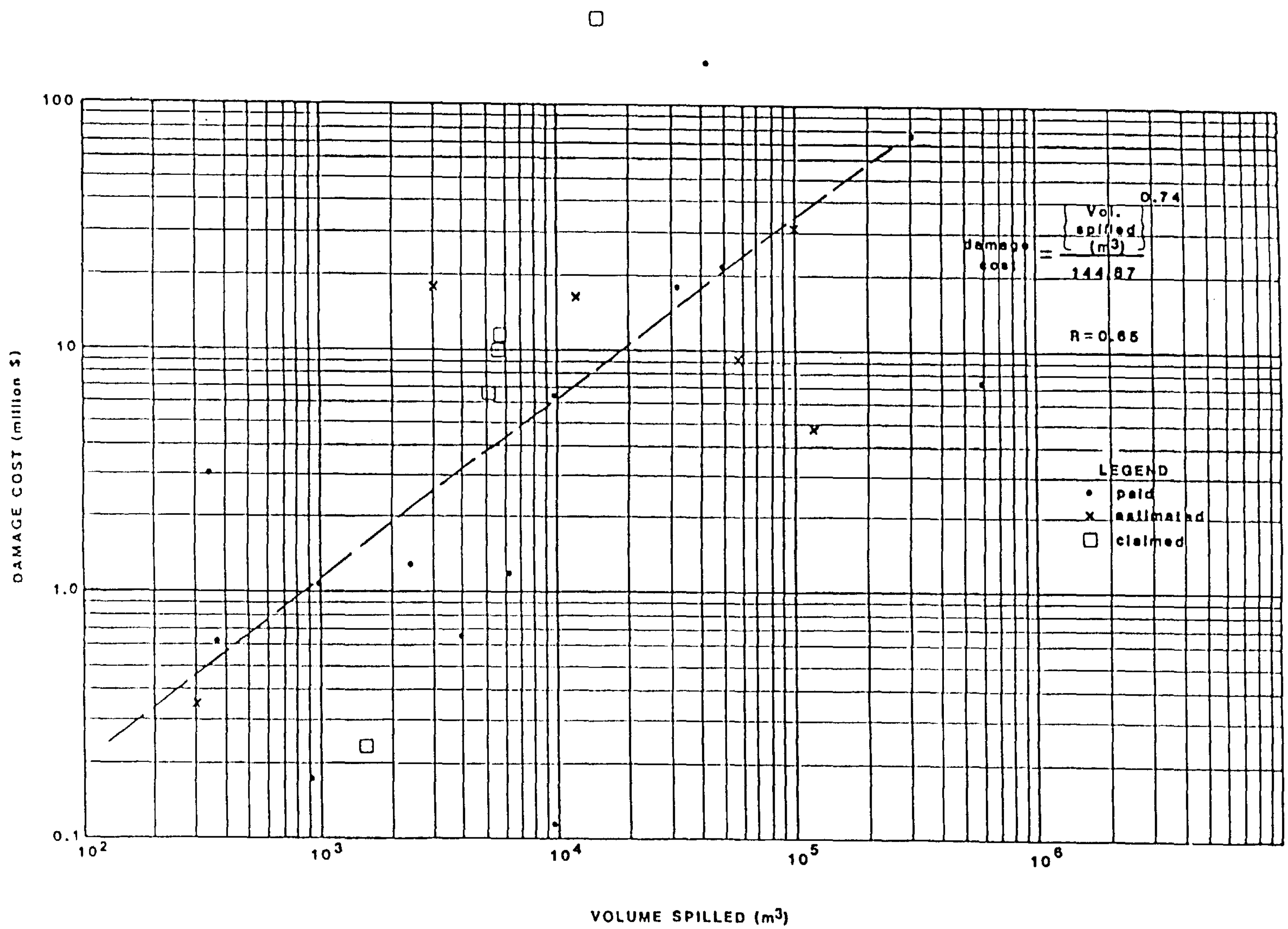


FIGURE 18 OILSPILL DAMAGES VS. VOLUME SPILLED

The data for this last graph correlate poorly and should be used only as an indication of the order of magnitude of spill damage costs. Location, timing, presence of sensitive resources, and socio-economic levels all play a strong role in determining oil spill damage costs. It is impossible to predict in advance these types of costs.

With these graphs it is possible to estimate offshore spill response costs and, in conjuction with real-time monitoring and trajectory modelling, shoreline cleanup costs. The range of oil spill damage costs can also be estimated. Table 3 gives the actual cost breakdown for eight past offshore blowouts.

Case Histories

In order to more fully illustrate the implications and consequences of oil-well ignition, several case studies are presented during which either a decision was made to allow an accidentally ignited blowout to burn or considerable effort was expended to prevent ignition of the blowout. It is significant that no amply documented blowout could be found in which the products were deliberately ignited, though other summary reports (Westergaard 1980; Manadrill et al. 1985) make reference to such incidents. The case histories presented are those which are well documented and best illustrate the decision-making trade-off between safety (of both equipment and personnel) and environmental impact.

Ekofisk Bravo. (from Andersen et al. 1977) On April 22, 1977 an uncontrolled blowout occurred on the production platform Ekofisk B - "Bravo" - in the Norwegian sector of the North Sea. About 2800 m^3 of oil and 1.5 million m^3 of gas flowed daily from the well, located about 280 km from the nearest shore.

TABLE 3

HISTORICAL OFFSHORE BLOWOUT CLEANUP AND SPILL DAMAGE COSTS

INCIDENT	AREA	DATE	LOCATION	FIRE STATUS	VOLUME SPILLED (m^3)	SHORELINE OILED (km)	CLEANUP DURATION (days)	CLEANUP COST (millions of 1985 Canadian dollars)	DAMAGE COST
MAIN PASS	MISSISSIPPI	1970	nearshore	on fire till capping began	8,000	16	51	8.94	79.5*
EKOFISK	NORTH SEA	1977	offshore	no fire	23,000	0	7	12.12	0
FUNIWA 5	NIGERIA	1980	nearshore	no fire	32,000	unknown	unknown	5.36	16.89*
HASBAH 6	SAUDI ARABIA	1980	offshore	no fire	13,000	300	150	17.68	0
IXTOC 1	MEXICO	1979	offshore	gas boil ignited	530,000	1600	180	62.60	365*(7.4+)
SANTA BARBARA	CALIFORNIA	1969	nearshore	no fire	12,500	10	360	27.22	15.9!
BAY MARCHAND	LOUISIANA	1970	nearshore	on fire	10,000	24	223	5.96	0
UNIACKE	SCOTIAN SHELF	1984	offshore	no fire	1,000	0	7	0.67	0

! estimated

* claimed

\+ paid

Shortly after the blowout occurred the other 14 wells on the platform were shut in and the platform was evacuated. Within 40 minutes a fire-fighting vessel approached the platform and began to deluge it with water at a rate of 4000 m^3/hr, an operation that continued until the well was capped. It is reported that at no time was ignition of the well considered; every effort was made to prevent ignition.

As the well was emitting a considerable quantity of gas, it was agreed the following day that should the wind veer towards the other platforms in the field (15 in total) all production would cease. On April 25 the wind veered and production (other than gas for power) in the whole complex was halted. Later that day the operator requested permission to restart and at midnight this was granted by the On-Scene Commander. On the April 26 production was halted again for about 4 hours due to changing weather conditions. On April 28 the government ordered (without consulting the On-Scene Commander) all production to cease. Production did not resume until the well was killed two days later.

The well was killed on April 30 after three earlier unsuccessful attempts. The main problem was that the BOP (blind rams only) was inverted, thus the kill line nipple was on the wrong side of the rams. Two valves were eventually mounted on top of the inverted BOP, the BOP was closed (shop tests had confirmed that the rams could hold the $3x10^4$ kPa (4200 psi) well-head pressure), the upper two valves were closed, the BOP was opened, and mud was pumped in through the kill line. The elapsed time from the blowout occurring to the final kill was seven days, 19 h and 45 min. Simultaneous with the capping operation the operator was ordered to commence two relief wells. By the time the well was finally capped, two rigs had been chartered but neither was at the site yet.

The spill cleanup operation involved both application of dispersants (around the Bravo platform and others, when slicks approached, for fire prevention), and containment and recovery operations in the vicinity of the blowing well.

Fifty eight cubic metres of dispersant were applied, from four vessels, to oil near platforms in the three days following the blowout. No measurements of effectiveness are reported. Once the wind shifted and drove the oil away from neighbouring platforms the dispersant operation was stopped and was never recommenced.

Skimmers and booms first arrived at the site 56 h after the blowout occurred. Altogether 5,915 m of boom, seven skimmers, 25 vessels, and 200 people were involved in the mechanical cleanup effort. In total 1,610 tons of emulsion (containing 870 tons of oil) were recovered over the six day operation, 83% of that by one Framo skimmer. The total oil recovered was only about 7% of the total spilled.

Fortunately, the oil did not drift towards a coastline and, due to the time of year, no major fish or sea-bird impacts were recorded. All the oil dispersed naturally over the following several weeks without causing recorded damage.

The cost of the cleanup operation has been estimated at U.S. $12 million. No damage costs have been reported.

In hindsight, the decision to prevent ignition of the well was the correct one. Fire would have severely hampered a relatively simple capping operation, might have caused the failure and blowout of the other 14 wells on the platform, and finally, would have resulted in a lengthy and costly relief well program.

As the spilled oil caused no significant environmental damage, even though the spill response operations were relatively inefficient, no environmental justification for igniting the well existed. The safety aspects of the escaping gas were dealt with properly by eliminating ignition sources both on the Bravo platform by water deluge and on adjacent platforms by ceasing production.

Platform Charlie, Main Pass. (from Alpine Geophysical Assoc. 1971) On February 10, 1970 a blowout and fire occurred on the unattended production platform Charlie in the Main Pass Block 41 field off the Louisiana coast. Eight of the 12 wells blew out and were on fire. An initial attempt to control the fire with two vessels equipped with water monitors failed, and well control experts were called in. The platform was left burning while fire, well control, and spill cleanup equipment were assembled on site. Virtually all the oil being released (400 to 1000 m^3/day) was burned in the fire.

After several weather and equipment delays and an unsuccessful attempt on March 9, the fire was extinguished, using dynamite, on March 10, 28 days after the blowouts began.

By this time the operator had in place a line of barges to contain and collect the escaping oil and was using dispersants in the vicinity of the platform to limit the danger of fire.

The first of the blowing wells was closed in on March 13 (one capped and one sanded up). The remaining wells were progressively killed by relief wells or capping until the last was under control (killed by a relief well) on March 31, 49 days after the blowout occurred. Many problems were encountered in the control operation because of fire damage to the platform, in many cases requiring the dynamiting of debris and well-heads to gain access. Some of the blowout plumes were deflected downward by debris.

In total the mechanical recovery system (including about 60 vessels and 250 men) skimmed about 4100 m^3 of 50% water-in-oil emulsion representing 20 to 35% of the estimated 5,600 to 10,500 m^3 of oil that escaped after the fire was extinguished. Two hundred and forty cubic metres of dispersant were applied, as a safety measure, at the platform using a water monitor. No dispersant efficiency data were reported.

Although the spill occurred in a biologically important area for birds, shellfish and shrimp, little evidence of acute biological impacts were reported. Some oiling of shorelines occurred, but these were quickly and completely cleaned. Some oiling of fishing nets and recreational boats was reported. A number of law suits were initiated by fishermen alleging damages and the sales of Louisiana shellfish and fish were alleged to decline due to buyer fear of tainting.

The total cost of the spill cleanup was about U.S. $9 million. The claimed damages amounted to U.S. $79.5 million.

In retrospect, after the initial attempts to douse the fires failed, the decision to allow the wells to burn until well and spill control operations were in place was correct. This dramatically reduced the volume of oil spilled and thus the potential damages. Until March 10, when the fire was extinguished, almost no oil landed on the sea surface. After the fire was extinguished it took only three days to cap the first well, despite the fire damage, and a further three days to reduce the oil outflow by half.

Despite the rather crude (by today's standards) containment and recovery system put together for the incident an impressive recovery efficiency was achieved. This was primarily due to the lead time available and the planning of spill control operations done before the fire was extinguished.

Unfortunately, because of the fire damage, poor weather and equipment failures, oil did escape and, despite the best efforts of the operator, large damage suits were initiated. This illustrates that, in a biologically important area, even the best plans and efforts may not counteract the perceptions of oil spills by the general public.

Ixtoc-1. (from Golob and McShea 1980; and Ross et al. 1979) On June 3, 1979 the Ixtoc-1 exploratory well blew out and shortly after caught fire. The fire melted the drilling derrick and destroyed most of the equipment on the semi-submersible platform. The derrick eventually collapsed into the sea, damaging the marine riser, the BOP and the casing beneath the stack. By the next day the platform had been towed off the well where a large fire was burning. The platform was eventually declared a total loss and was scuttled.

Oil flowed to the sea surface from the BOP at a rate estimated at 4800 m^3/day and, by the time the well was finally brought under control 295 days after the blowout, a total of 530,000 m^3 of oil had been spilled.

Well control operations involved both attempts to close the BOP and the drilling of relief wells. The surface fire was deliberately left burning to eliminate explosion hazards for nearby well and spill control operations. By June 22, despite high currents, poor visibility, and debris around the well-head, control lines were attached to the well-head and by June 28 several unsuccessful attempts had been made to close the BOP. At one time the well was sealed successfully for 4 h until pressure ruptured the casing below the BOP. The well was reopened to prevent further damage to the casing. In August the operator injected 100,000 steel and lead balls into the well in an attempt to reduce the flow. Reports on the success of this operation vary, ranging from a reduction in oil flow to 1,590 m^3/day to no effect since the balls were quickly ejected from the well.

After a series of mechanical problems and misses the well was finally killed by a relief well 295 days after the blowout occurred.

A considerable ($63 million) effort was expended to contain and recover or aerially disperse the emulsified oil from the blowout. Overall, less than 5% of the oil was recovered (some of which had to be discharged back to the sea for lack of tankage). About $12 million worth of dispersant was applied to the oil slicks. Considerable controversy still exists as to whether or not this program was effective on the weathered, emulsified oil.

During the early stages of the blowout, samples of the surface oil near the site indicated that it had been exposed to high heat (from the gas fire) and that it lost 30 to 40% of its light ends. It was theorized that this promoted the formation of an emulsion in the extremely turbulent boil zone. Later, as the flowrate subsided the emulsion formation was less pronounced and one report indicates that when the fire was momentarily extinguished during the final kill procedures, the surface oil was unemulsified. It is by no means certain that the surface fire promoted emulsion formation; changes in turbulence level and oil characteristics as the reservoir depleted could have been equally responsible.

The environmental impacts of the Ixtoc-1 blowout, though real, were not nearly as great as would be expected for a spill of this magnitude. Fish catches were reduced by 50% in some areas and octopus catches were down by 70% in others. The declines in catches may have been partially caused by storms in the area. It seems that many fish moved away from the oil since areas remote from the spill reported catches four times normal levels. Impacts on sea-birds appear to have been negligible.

About 1500 km of shoreline was oiled, with severe damage in some areas. It was reported that the combination of spilled oil and fall storms killed as many as 50% of the intertidal populations along the coast, though the severe storms could have been solely responsible.

Suits for at least U.S. $365 million were filed by U.S. fishermen, resort operators, states, counties and towns for damages resulting from the spill. To date only $7.4 million has been paid by the operator since Mexican authorities claim that U.S. courts have no jurisdiction in the matter.

In retrospect it is unfortunate that, once the fire had started, the rig was not left in place even though it was severely damaged. Based on the combustion model presented earlier it is likely that a combustion efficiency of at least 98% could have been achieved for a surface release as opposed to a subsea release. In addition, assuming the platform survived the fire, the absence of the gas plume in the water would have made diving operations much less hazardous and certainly would not have hampered relief well drilling. Had the fire been rapidly extinguished or not ignited in the first place the well could have been brought under control rapidly and the high cost of the Ixtoc-1 control effort could have been avoided.

Uniacke G-72 (from Hart 1984; and Gill et al. 1985). On February 22, 1984 the Uniacke G-72 well, located about 180 km off Halifax, Nova Soctia, blew out. About 50 m^3 of condensate per day and a unknown amount of gas was released from the riser.

Ten days later, after waiting for safe access and equipment a well control team boarded the platform, shut the annular preventer, diverted the gas to the flare (unignited), and pumped mud down the choke line, thus killing the well.

Because of the low flowrates of condensate and its highly volatile nature, no spill cleanup operations were mounted or considered necessary. Instead, an extensive monitoring program was instituted which showed that the condensate was indeed dissipating within a few kilometres of the blowout site. No environmental impacts or damage claims have been reported. The monitoring program cost $670,000.

In hindsight, non-ignition of the well was the correct decision: potential impacts of the condensate were small and fire would have greatly hampered and delayed what was a simple exercise in well control.

KEY DECISION-MAKING FACTORS

This chapter presents a description of the key issues that must be addressed in the process of deciding whether or not to ignite or to extinguish a blowing well. The content of the chapter is a compendium of the previous chapters' analyses and comments from personal interviews with representatives of industry and government. The key decision-making factors that have been identified are:

* cost
* timing
* human safety
* well control
* other spill control operations
* environmental impact
* combustion efficiency
* insurance implications

Well ignition, as a last resort for spill control, should be considered as an option from the moment the blowout occurs until the well is finally controlled. Unless the unignited blowout poses an immediate and acute danger to human life, the well should not be ignited immediately unless it can be safely diverted and flared. Only after carefully weighing the advantages and disadvantages of ignition, reviewing the ongoing well control operations, and evaluating the efficiency of other spill control techniques should ignition of the blowout be planned. Past experience has indicated that the time frame for this can range from one day to two weeks. The exception to this is the case of subsea blowouts where immediate ignition of the gas boil has significant benefits for well control operations, provided that the rig has been moved to safety.

HUMAN SAFETY

Sour Gas

Human safety should be of paramount importance in considering well ignition or extinction. If H_2S poses an acute hazard (see Figure 9) to workers or to nearby residents, serious consideration should be given to developing a written policy calling for immediate ignition of wells on Canada lands if certain limits are exceeded (for example, some operators in Alberta use 20 ppm in unevacuated areas as the limit for requiring ignition).

Extreme caution should be used in deciding to extinguish a burning sour gas well. Such operations should not be undertaken unless appropriate evacuations are made (see Figure 9), weather conditions are suitable, safety equipment is available, and all possible preparations are made for fire and well control. It would be prudent to have equipment available to quickly re-ignite the well if control operations are not immediately successful or are delayed.

Oil Wells

No oil well should ever be ignited or extinguished intentionally if such action poses a major threat to human safety.

Key safety factors that must be considered when contemplating ignition of a well include: wind speed and direction, location of ignition sources, safe egress from the site, concentrations of gas, and potential location of gas pockets or pools of liquid hydrocarbons in areas near the well. The same factors must be considered for extinguishing a burning well.

WELL CONTROL

The primary objective of any response to a blowout must be killing the well safely and stopping the source of any potential pollution. Because igniting the well usually hampers and delays the well control effort, it is not prudent to ignite the blowout immediately unless there is an acute threat to human life. Once surface well control efforts have proven fruitless the option of ignition to protect an environment should be considered.

In the case of extinguishing a burning blowout a slightly different situation exists. If the well cannot be extinguished within a few hours of its ignition the damage to the rig and ancillary equipment will have already been done. At this point the advice of well control specialists should be sought as to the advisability of extinguishing the fire. The exception to this would be for a MODU blowout where extended exposure to heat may cause sufficient damage to sink the MODU, further complicating any well control and site restoration efforts.

SPILL CONTROL TECHNIQUES

Various countermeasures techniques and equipment can be used to control an oil spill resulting from a blowout. The efficiency of a spill cleanup operation depends on many factors, each unique to the specific situation. In some situations countermeasures can be extremely effective in limiting the impact of the oil spill (i.e., spills on land or surface blowouts offshore in a complete ice cover) whereas in others countermeasures are unlikely to greatly reduce the oil's impact (i.e., blowouts offshore in open water).

Considerations in estimating the efficiency of any spill control operation include: state of preparedness, weather, sea state, spreading and movement of the oil, the availability and location of equipment, logistics support and manpower resources.

Extinguishing a subsea blowout presents a special case. If the gas presents a negligible hazard to operations at the site, consideration should be given to putting out the fire as the possible elimination of emulsion formation could greatly enhance the efficiency of near-source spill control efforts. If this does not prove to be the case the gas can always be reignited.

ENVIRONMENTAL IMPACT CONSIDERATIONS

It is very difficult to predict for a specific blowout what environmental damage it may cause, let alone what the cost of the damage may be. If a vulnerable, sensitive resource is threatened by oil from a blowout the public pressure to prevent damage, regardless of the cost, can be overwhelming. The damage claims arising from oil-well blowouts can be astronomical and many years can be spent litigating these claims. It must also be remembered that, even if no demonstrable physical damage occurs, severe economic loss can be suffered by renewable resource harvesters in the area because of the public's fear of purchasing possibly tainted products. It is impossible to predict whether or not ignition of the blowing well, especially if oil has already been released for some time, will eliminate or even reduce these concerns and subsequent damage claims. In the end, the perceived threat to sensitive, particularly endangered, species may override any engineering or financial reasoning and may force a decision to ignite a well, if ignition will eliminate the perceived threat.

COMBUSTION EFFICIENCY

In order for ignition of a blowout to be an effective spill control option it must eliminate the threat posed by the blowout products. In the case of gaseous products, combustion efficiencies will be virtually 100%. In the case of liquid hydrocarbons the combustion efficiency depends on several factors, primarily the blowout type (surface or subsea) and oil and gas flowrates (see Figure 11). It is suggested that, if the ignition of the well is likely to result in less than about a 75% combustion efficiency (based on 75% of the oil burning before it leaves the plume and the remainder burning as it falls), then it should not be considered a viable option since the unburned oil will still require a spill control operation and may cause as much environmental damage as the full flowrate of oil.

COST

Once a point in the blowout response has been reached at which it is likely that the situation will continue for some time, a rough cost/benefit analysis can be undertaken to assess the economics of igniting the well. Given that a high combustion efficiency could be achieved, the cost of rig damage and increased well control costs can be compared with the savings in offshore cleanup costs and, in conjuction with a spill trajectory analysis, the savings in shoreline and nearshore cleanup costs. The values of potentially recoverable oil (from spill control) and lost oil and gas should be taken into consideration.

A similar analysis should be conducted in the case of extinguishing a burning well. A comparison of the cost of the various well control options with possible spill cleanup costs would be a useful decision-making aid.

INSURANCE IMPLICATIONS

One complicating factor in assessing the cost/benefit of well ignition/extinction is the implication of the actions on insurance policies and other sureties posted for drilling on Canada lands. For example, the cost of rig and equipment damage as a result of intentional ignition may or may not be covered by insurance, under the "deliberate damage" clause found in most policies, and may or may not be claimable against the "no fault" surety posted with the government for damages as a result of spills on Canada lands. On the other hand, spill cleanup costs may or may not be recoverable under the "no fault" surety up to some limit, whether or not the well is ignited. Spill damage claims are covered, up to a specified limit, under the "no fault" surety but the amount recoverable depends on how much of the equipment damage and cleanup costs are applied to the surety. Operators may also carry insurance for damage claims exceeding the regulatory limits.

Finally, in this time of rapidly escalating premiums for environmental liability insurance and enormous claims and settlements paid as a result of accidents, the implications of the spill on future premiums must also be carefully examined.

As each operator's situation is unique, it is recommended that insurance experts be consulted both prior to and during any decision-making on well ignition.

DECISION-MAKING AIDS

This section presents check-lists of the key decision-making factors and other important considerations in ignition/extinction of blowouts. It is emphasized that these check-lists are not provided as strict instructions but merely as an aid to decision-makers.

Separate check-lists have been developed for sour gas, land, and offshore (surface and subsea) blowouts. Each check-list contains the key questions that should be answered during the decision-making process; following each question is a list of factors to consider in answering the question. Each check-list is followed by a flowchart to aid in the decision-making process.

There are four check-lists pertaining to igniting a well blowout for safety or environmental reasons. Following these are four check-lists for extinguishing a burning well blowout.

CHECK-LIST FOR IGNITING H_2S BLOWOUTS

1. Is sour gas being released?

2. If so, does it pose a threat to humans?

   * concentration and flowrate of sour gas
   * proximity of human populations and transportation corridors
   * wind speed and direction
   * atmospheric dispersion predictions (Figures 4, 5 and 9)
   * predicted or measured H_2S concentrations in unevacuated areas
   * policy on H_2S concentrations for compulsory ignition
   * evacuation status
   * proximity of topography or structures that may cause gas to concentrate (valleys, cliffs, platforms, etc.)

3. Does the sour gas pose a threat to animals?

   * location of major herds of animals or flocks of birds

4. Can the well be controlled quickly and safely?

   * status of rig, well-head, control and ancillary equipment
   * opinion of well control experts on success and timing of capping operations
   * opinion of well control experts on implications of fire vis-a-vis well control
   * cost of well control options
   * explosion/accidental ignition (Figures 3 and 8)
   * safe, controlled access/egress to/from site
   * diversion and flaring of blowout products
   * availability of fire prevention equipment

5. If surface control is not possible or has failed is the likelihood high of the well bridging or the reservoir sanding up or depleting?

   * amount of hole cased
   * observations of well flow
   * geology of area/other wells

6. If a relief well is required will ignition be advantageous?

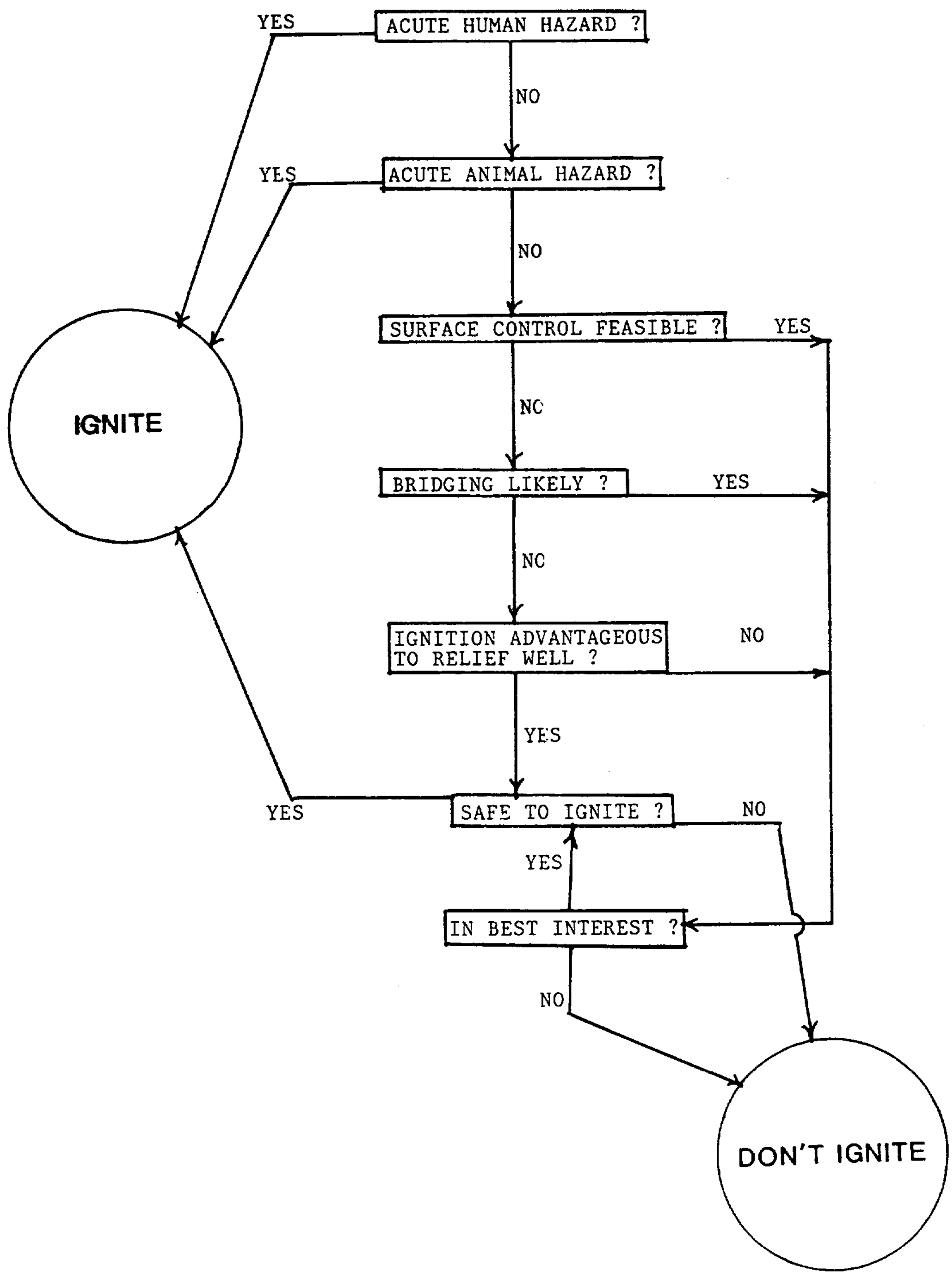
   * optimum location of relief well
   * estimated time to kill well
   * use of existing rig for relief well
   * explosion/accidental ignition potential vis-a-vis weather/terrain (Figures 3 and 8)
   * radiated heat (Figures 13 and 14)
   * insurance implications
   * cost of relief well
   * diversion and flaring of blowout products
   * potential for future, long term impacts of H_2S vs. SO_2
   * ability to extinguish fire

7. Is it in the best interest of the operator to ignite the well?

   * corporate image
   * media coverage
   * public perception
   * effect on future government approvals
   * future insurance implications
   * likelihood of major hardship or inconvenience to public
   * loss of rig
   * cost/savings

FIGURE 19

RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR IGNITING H_2S BLOWOUTS



CHECK-LIST FOR IGNITING LAND BLOWOUTS

1. Is there an acute hazard to human safety?

   * sour gas (see sour gas check-list and Figures 4, 5 and 9)
   * explosion/fire potential (Figure 8)
   * proximity of human populations and transportation corridors
   * gas dispersion predictions (Figure 8)
   * evacuation of people at risk
   * proximity of topographic features that may concentrate gas

2. Is oil being released by the blowout?

   * flowrate, GOR
   * oil pooling/movement

3. Is surface well control feasible?

   * status of rig, well-head, control and ancillary equipment
   * safe access/egress
   * opinion of well control experts on feasibility and timing of surface kill
   * opinion of well control experts on implications of fire vis-a-vis well control
   * likelihood of accidental ignition/explosion
   * availability of fire prevention equipment
   * cost of well control
   * possibility of diversion and flaring
   * ability to extinguish fire if ignited

4. If not, is the likelihood high of the well bridging or the reservoir sanding up or depleting?

   * amount of hole cased
   * geology of area/other wells
   * observations of well flow

5. If a relief well is required will ignition be advantageous?

* optimum location of relief wells
* estimated time to kill well
* use of existing rig to drill relief well
* explosion/accidental ignition zones vis-a-vis weather/terrain (Figure 8)
* radiated heat (Figure 13)
* cost of relief well
* cost of rig damage
* cost of potentially recoverable oil
* insurance implications
* possibility of diversion and flaring
* ability to extinguish fire if ignited

6. Is potential environmental damage high?

* spreading and movement
* pooling of oil
* location of water courses and drinking water sources
* permafrost/snow/ice
* precipitation
* location and timing of sensitive resources
* damage costs

7. Can the oil be cleaned up and the area restored using conventional countermeasures?

* state of preparedness
* containing oil spread
* cleanup equipment available
* likely efficiency of cleanup
* cleanup damaging environment
* restoration of oiled area
* cost of cleanup and restoration
* weather
* terrain

8. Would ignition result in efficient combustion? (Figure 11)

* type of blowout
* oil flowrate
* gas flowrate
* water flowrate
* size of orifice
* orientation of orifice
* debris in plume

9. Can the well be safely ignited?

* location and weather
* terrain and topography
* safe access/egress
* appropriate equipment
* gas concentrations in area

10. Are the effects of igniting the well unacceptable?

* rig/equipment damage
* delay in well control
* grass/tundra/forest fire potential
* radiated heat (Figure 12)
* "rain" of burning oil (Figure 11)
* soot
* insurance liability

11. Is well ignition economically advantageous?

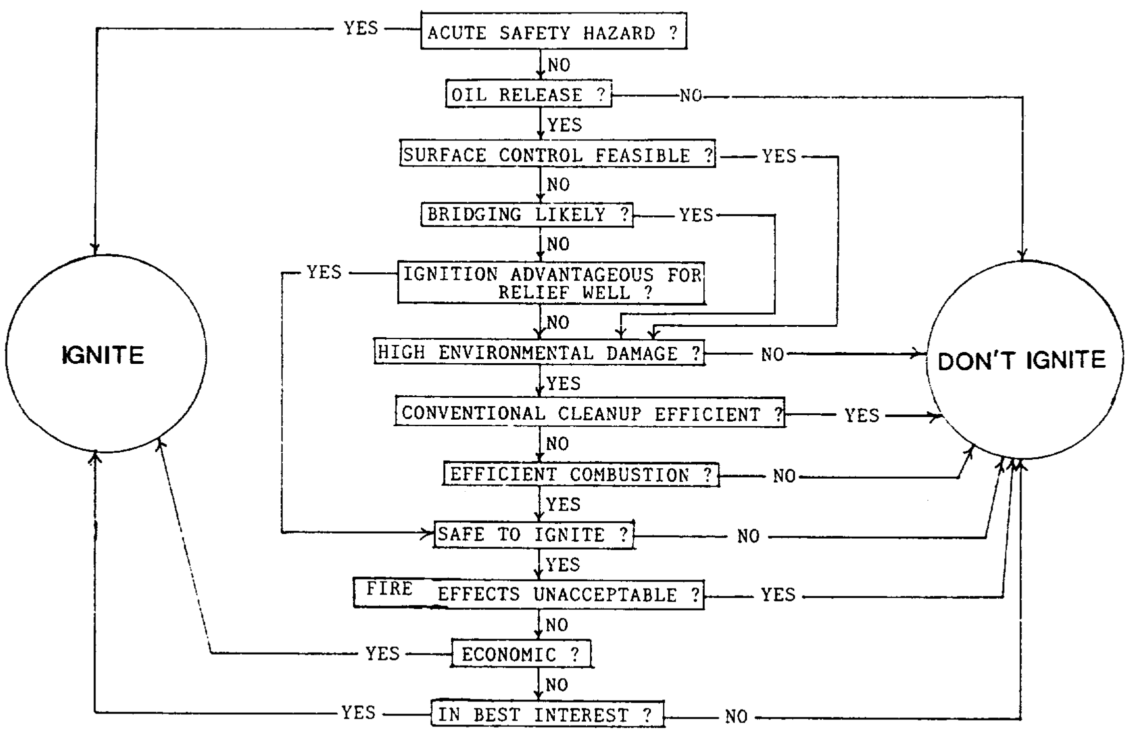
* cost of
  - rig and equipment
  - lost oil and gas
  - relief well drilling

* savings in
  - surface well control
  - spill control and cleanup (Figure 16 & 17)
  - damage claims (Figure 18)

12. Is it in the best interest of the operator to ignite the well?

* corporate image
* media coverage
* public perception
* effect on future government approvals
* future insurance implications
* likelihood of major hardship or inconvenience to public

FIGURE 20
RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR IGNITING LAND BLOWOUTS



CHECK-LIST FOR IGNITING OFFSHORE SURFACE BLOWOUTS

1. Is there an acute hazard to human safety?

   * sour gas (see sour gas check-list and Figures 4, 5 and 9)
   * explosion/fire potential (Figure 8)
   * proximity to human populations or transportation corridors
   * gas dispersion predictions (Figure 8)
   * evacuation of people at risk
   * proximity of features that may concentrate gas

2. Is oil being released by the blowout?

   * flowrate, GOR
   * oil thickness and movement
   * emulsification

3. Is surface well control feasible?

   * status of platform, rig, well-head, control and ancillary equipment
   * safe access/egress
   * opinion of well control experts on feasibility and timing of surface kill
   * opinion of well control experts on implications of fire vis-a-vis well control
   * opinion of experts on implications of fire vis-a-vis platform stability
   * likelihood of accidental ignition (Figure 8)
   * availability of fire prevention equipment
   * cost of well control
   * possibility of diversion and flaring
   * ability to extinguish fire if ignited

4. If not, is the likelihood high of the well bridging or the reservoir sanding up or depleting?

   * amount of hole cased
   * geology of area/other wells
   * observations of well flow

5. Is the platform or rig going to be pulled off the well-head?

   * implications for well control
   * conversion to subsea blowout
   * use of platform to drill relief well
   * damage to platform and stability
   * efficiency of countermeasures for subsea blowout
   * rapid emulsification of oil with subsea blowout
   * initial slick thickness of subsea vs. surface blowout (natural dispersion)
   * combustion efficiency of surface vs. subsea blowout (Figure 11)
   * insurance implications
   * possibility of diversion and flaring

6. Would ignition of the blowout be advantageous to relief-well drilling?

   * optimum location of relief wells
   * estimated time to kill
   * use of platform to drill relief well
   * explosion/accidental ignition zones (Figure 8)
   * radiated heat (Figure 13)
   * cost of relief well
   * cost of rig and platform damage
   * cost of potentially recoverable oil
   * insurance implications
   * possibility of diversion and flaring
   * ability to extinguish fire if ignited

7. Is potential environmental damage high?

* time of year
* weather and sea state
* spreading and movement of oil
* trajectory modelling
* proximity to sensitive areas
* evaporation and natural dispersion
* potential damage costs (Figure 18)

8. Can the oil be cleaned up and the area restored using conventional countermeasures?

* state of preparedness
* weather and sea state
* spreading and movement of oil
* availability of equipment
* efficiency of cleanup
* protection of sensitive areas
* cleanup of oiled areas
* restoration of damaged resources
* cost of offshore and onshore cleanup and restoration (Figures 16 and 17)

9. Would ignition result in efficient combustion? (Figure 11)

* oil flowrate
* gas flowrate
* water flowrate
* size of orifice
* orientation of orifice
* debris in plume

10. Can the well be safely ignited?

* weather
* safe access/egress
* appropriate equipment
* gas concentrations and explosions (Figure 8)

11. Are the effects of igniting the well unacceptable?

* platform/rig/equipment damage
* delay in well control
* explosions (Figure 8)
* radiated heat (Figure 13)
* "rain" of burning oil (Figure 11)
* soot
* insurance liability

12. Is well ignition economically advantageous?

* cost of
  - platform, rig and equipment
  - lost oil and gas
  - relief well drilling

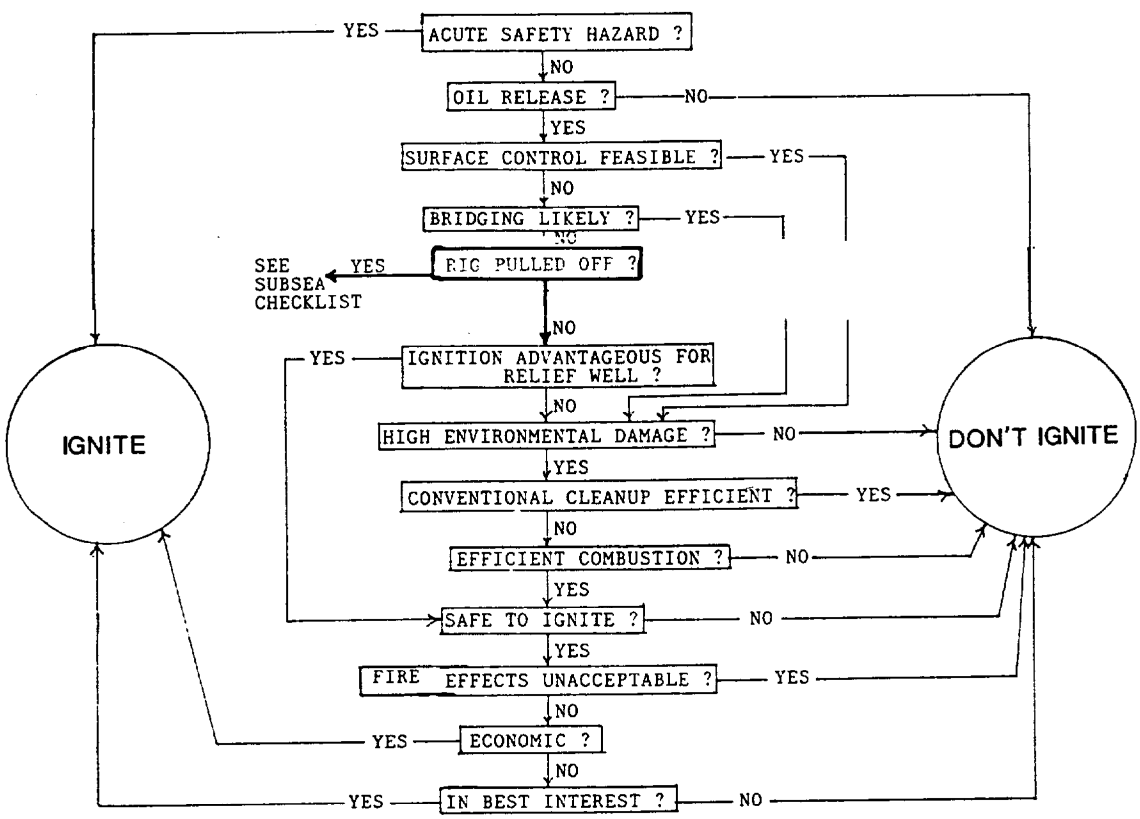
* savings in
  - spill control and cleanup (Figure 16 and 17)
  - damage claims (Figure 18)
  - surface well control

13. Is it in the best interest of the operator to ignite the well?

* corporate image
* media coverage
* public perception
* effect on future government approvals
* future insurance implications
* likelihood of major hardship or inconvenience to public

FIGURE 21

RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR IGNITING OFFSHORE SURFACE BLOWOUTS



CHECK-LIST FOR IGNITING SUBSEA BLOWOUTS

1. Is there an acute hazard to human safety?

   * sour gas (see sour gas check-list and Figures 4, 5 and 9)
   * explosion/accidental ignition potential (Figure 3)
   * proximity of human populations and transportation corridors
   * gas dispersion predictions (Figure 3)
   * evacuation of people at risk
   * likelihood of major hardship or inconvenience to public
   * proximity of features that may concentrate gas

2. Is oil being released by the blowout?

   * oil flowrate, GOR
   * oil slick thickness/spreading
   * emulsification

3. Will igniting the gas enhance well control?

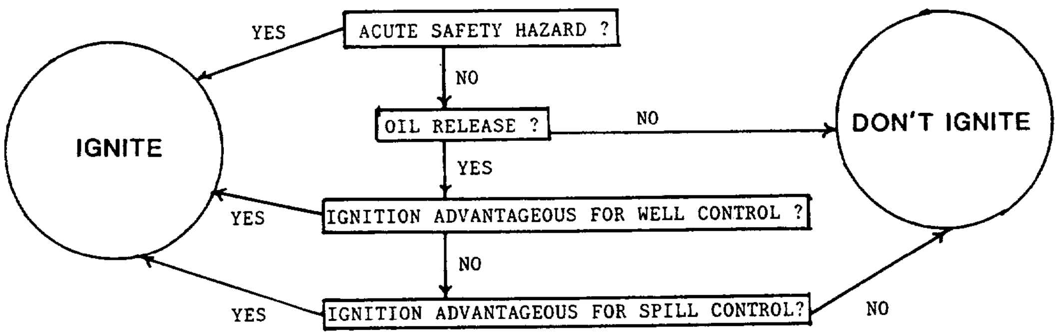
   * location of surface vessels near blowout
   * optimum location of relief wells
   * explosion/accidental ignition zones (Figure 3)
   * radiated heat (Figure 14)
   * subsea visibility
   * opinion of well control experts
   * ability to extinguish fire if ignited

4. Will ignition of the gas enhance spill control countermeasures?

   * state of preparedness
   * closer siting of recovery equipment if on fire
   * potential for enhanced emulsification
   * use of firelight for night-time operations
   * flashing of volatiles from oil

FIGURE 22

RELATIONSHIP AMONG QUESTIONS FOR
IGNITING SUBSEA BLOWOUTS



CHECK-LIST FOR EXTINGUISHING BURNING SOUR GAS BLOWOUTS

1. Will an acute hazard to human safety be created?

   * proximity to human populations and transportation corridors
   * H_2S flow and concentration
   * wind speed and direction
   * atmospheric dispersion predictions (Figures 4, 5 and 9)
   * topography/terrain
   * evacuation status
   * safety equipment for on-site personnel
   * safe access/egress
   * availability of fire extinguishing and suppression equipment
   * likelihood of accidental reignition/explosion (Figure 8)
   * preparedness to intentionally reignite well

2. Will surface control procedures be enhanced and speeded by extinguishing the fire?

   * extent of existing damage to rig, platform, well-head, control equipment and ancillary equipment
   * likelihood and extent of continuing damage or control problem worsening
   * opinion of well control experts
   * feasibility of diversion and flaring
   * state of readiness to begin well control
   * cost of well control options
   * safe access/egress
   * insurance implications

3. Is the likelihood high of the well bridging or the reservoir sanding up or depleting?

* amount of hole cased
* geology of area/other wells
* observations of flowrate

4. Will extinguishing the fire enhance relief-well drilling?

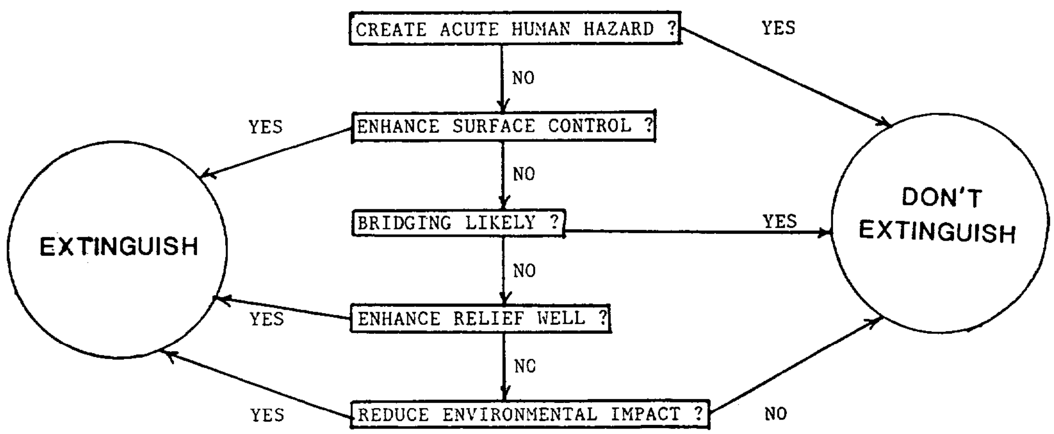
* optimum siting of relief well
* estimated time to kill well
* repair existing rig and use to drill relief well
* cost of relief well
* insurance implications
* wind speed/direction
* heat radiation (Figure 13)
* secondary fires
* toxicity and dispersion of SO_2 vs. H_2S (Table 2)
* explosion/ignition zones (Figure 8)

5. Will extinguishing the fire reduce the overall environmental impact of the blowout?

* wind speed, direction and dispersion (Table 2 and Figures 4, 5 & 9)
* relative impact of SO_2 and H_2S
* proximity of mammals or birds
* possibility of forest, grass or tundra fires
* insurance implications
* likelihood of major hardship or inconvenience to public

FIGURE 23

RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR EXTINGUISHING H_2S BLOWOUTS



CHECK-LIST FOR EXTINGUISHING BURNING LAND BLOWOUTS

1. Will an acute hazard to human safety be created?

    * sour gas (see sour gas check-list and Figures 4, 5 and 9))
    * proximity to human populations and transportation corridors
    * gas dispersion predictions (Figure 8)
    * accidental reignition/explosion (Figure 8)
    * wind speed and direction
    * fire extinguishing and supression equipment availability
    * safe access/egress
    * evacuation status
    * appropriate safety equipment availability
    * preparedness to reignite well

2. Is oil being released by the blowout?

    * oil flowrate and GOR
    * combustion efficiency (Figure 11)
    * droplet fallout

3. Will surface control procedures be enhanced and speeded by extinguishing the fire?

    * extent of existing damage to rig, well-head, control equipment and ancillary equipment
    * likelihood and extent of continuing damage or control problem worsening
    * opinion of well control experts
    * feasibility of diversion and flaring
    * state of readiness to begin well control
    * cost of well control options
    * safe access/egress
    * insurance implications

4. Is the likelihood high of the well bridging or the reservoir sanding up or depleting?

   * amount of hole cased
   * geology of area/other wells
   * observations of well flow

5. Will extinguishing the fire enhance relief-well drilling?

   * optimum siting of relief well
   * estimated time to kill well
   * repair existing rig and use to drill relief well
   * cost of relief well
   * wind speed/direction
   * heat radiation (Figure 13)
   * secondary fires
   * explosion zones/gas dispersion (Figure 8)
   * terrain/topography
   * predicted movement of oil on ground
   * insurance implications

6. Will extinguishing the well cause environmental damage?

   * oil flowrate
   * predicted oil movement/pooling
   * location of water courses and drinking water sources
   * permafrost/snow/ice
   * precipitation
   * location and timing of sensitive resources
   * damage costs

7. Can the oil be cleaned up and the area restored using conventional countermeasures?

   * containing oil spread
   * state of preparedness of cleanup equipment and team
   * likely efficiency of cleanup
   * damage to environment by cleanup
   * restoration of oiled area
   * cost of cleanup and restoration
   * weather
   * terrain
   * insurance liability

8. Is extinguishing the well economically advantageous?

   * cost of
     - spill control and cleanup
     - damage claims

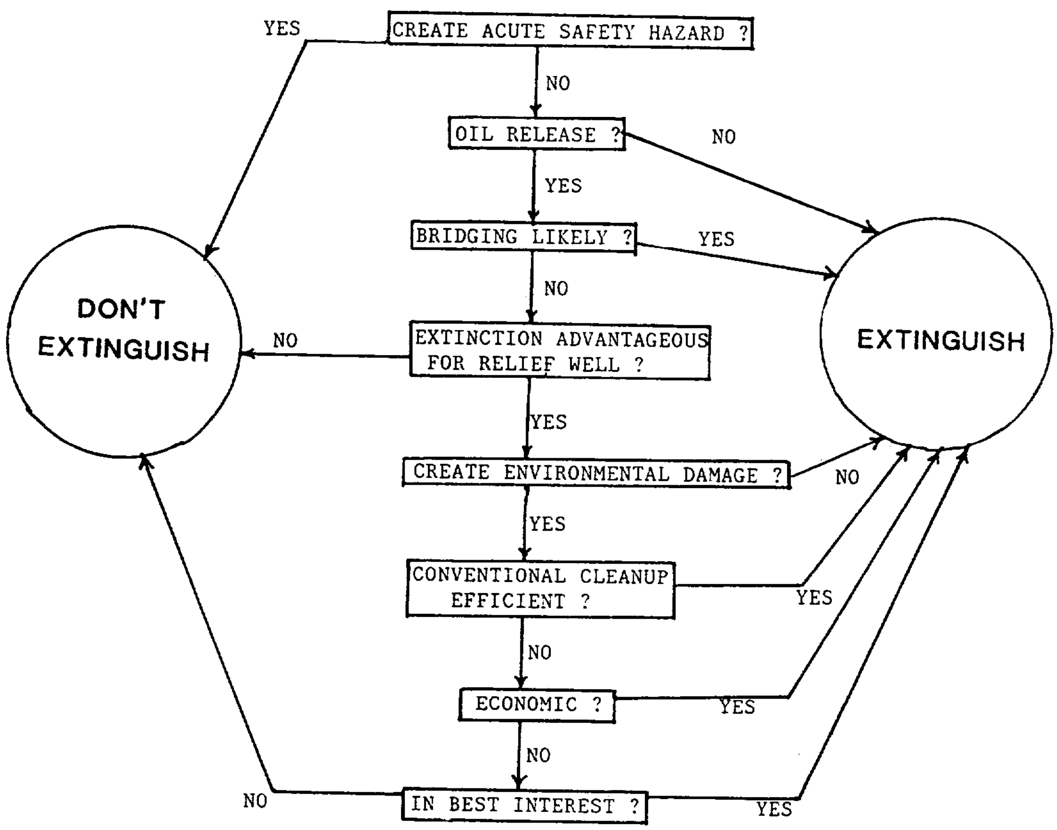
   * savings in
     - incremental rig and equipment damage
     - well control vs. relief well
     - recoverable oil value

9. Is it in the best interest of the operator to extinguish the well?

   * corporate image
   * media coverage
   * public perception
   * effect on future government approvals
   * future insurance implications
   * likelihood of major hardship or inconvenience to public

FIGURE 24

RELATIONSHIP AMONG QUESTIONS FOR EXTINGUISHING LAND BLOWOUTS



CHECK-LIST FOR EXTINGUISHING BURNING SURFACE BLOWOUTS OFFSHORE

1. Will an acute hazard to human safety be created?

   * sour gas (see sour gas check-list and Figures 4, 5 and 9))
   * proximity to human populations and transportation corridors
   * gas dispersion predictions (Figure 8)
   * accidental reignition/explosion (Figure 8)
   * wind speed and direction
   * fire extinguishing and suppression equipment availability
   * safe access/egress
   * evacuation status
   * appropriate safety equipment availability
   * preparedness to reignite well

2. Is oil being released by the blowout?

   * oil flowrate and GOR
   * combustion efficiency (Figure 11)
   * droplet fallout

3. Will surface control countermeasures be enhanced by extinguishing the fire?

   * extent of existing damage to platform, rig, well-head, control equipment and ancillary equipment
   * threat to stability of platform
   * likelihood and extent of continuing damage or control problem worsening
   * opinion of well control experts
   * feasibility of diversion and flaring
   * state of readiness to begin well control
   * cost of well control options
   * safe access/egress

4. Is the likelihood high of the well bridging or the reservoir sanding up or depleting?

   * amount of hole cased
   * geology of area/other wells
   * observations of flowrate

5. Is the platform going to be pulled off the well-head?

   * implications for well control
   * cost of platform
   * conversion to subsea blowout
   * extent of existing rig and platform damage
   * survivability of platform in fire
   * increased well control difficulty and cost
   * emulsification of subsea blowout oil
   * efficiency of countermeasures for subsea blowout
   * combustion efficiency of surface vs. subsea blowout (Figure 11)
   * insurance implications

6. Will extinguishing the fire enhance relief-well drilling?

   * optimum siting of relief well
   * estimated time to kill well
   * repair existing rig and use to drill relief well
   * cost of relief well
   * wind speed/direction
   * heat radiation (Figure 13)
   * secondary fires
   * explosion zones/gas dispersion (Figure 8)
   * slick drift
   * insurance implications

7. Will extinguishing the well cause environmental damage?

   * oil flowrate
   * slick trajectory predictions
   * evaporation and dispersion
   * location and timing of sensitive resources
   * sea state
   * wind speed and direction
   * current speed and direction
   * damage costs (Figure 18)

8. Can the oil be cleaned up and oiled areas restored using conventional countermeasures?

   * weather and sea state
   * spreading and movement of oil
   * state of preparedness of cleanup equipment
   * efficiency of cleanup
   * protection of sensitive areas
   * cleanup of oiled areas
   * restoration of damaged resources
   * cost of offshore and onshore cleanup and restoration (Figures 16 and 17)
   * insurance liability

9. Is extinguishing the well economically advantageous?

   * cost of
     - spill control and cleanup (Figures 16 and 17)
     - damage claims (Figure 18)

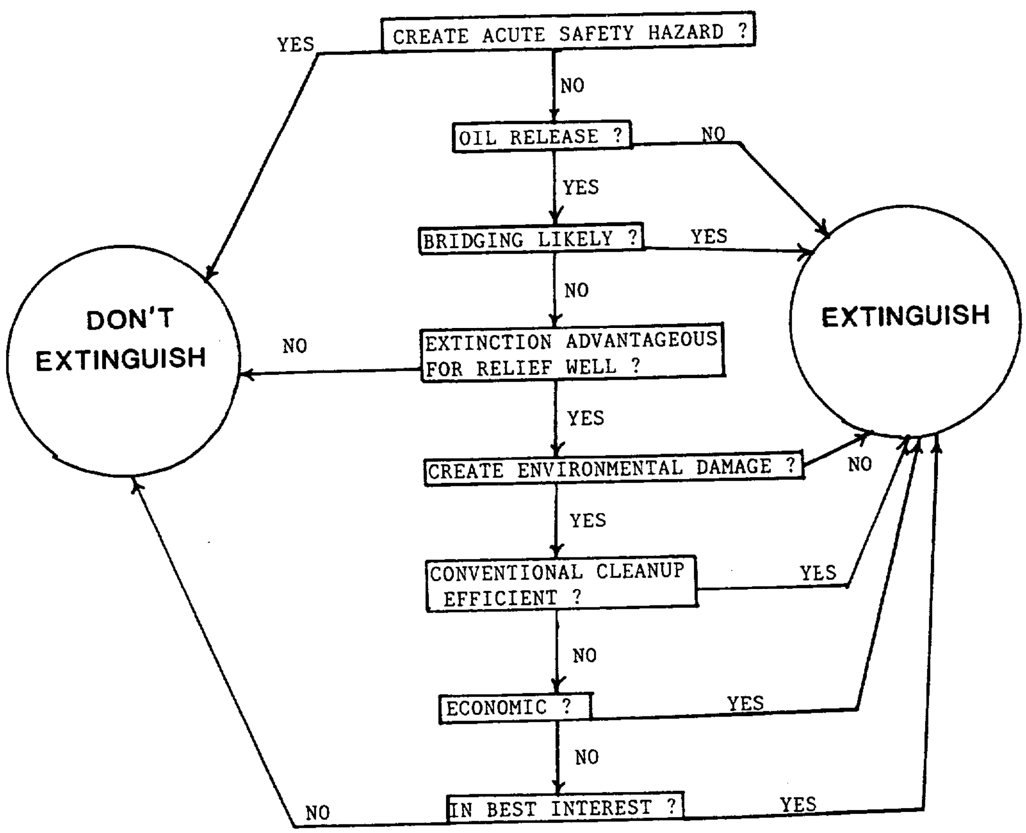
   * savings in
     - incremental rig and equipment damage
     - well control vs. relief well
     - value of recoverable oil

10. Is it in the best interests of the operator to extinguish the well?

* corporate image
* media coverage
* public perception
* effect on future government approvals
* future insurance implications
* likelihood of major hardship or inconvenience to public

FIGURE 25

RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR
EXTINGUISHING OFFSHORE SURFACE BLOWOUTS



CHECK-LIST FOR EXTINGUISHING BURNING SUBSEA BLOWOUTS

1. Will an acute hazard to human safety be created?

   * sour gas (see sour gas check-list and Figures 4, 5 and 9))
   * proximity to human populations and transportation corridors
   * gas dispersion predictions (Figure 3)
   * accidental reignition/explosion (Figure 3)
   * wind speed and direction
   * fire extinguishing and suppression equipment availability
   * safe access/egress
   * evacuation status
   * appropriate safety equipment availability
   * preparedness to reignite well
   * likelihood of major hardship or inconvenience to public

2. Is oil being released by the blowout?

   * oil flowrate and GOR
   * slick thickness/spreading
   * emulsification

3. Will extinguishing the gas fire enhance well control?

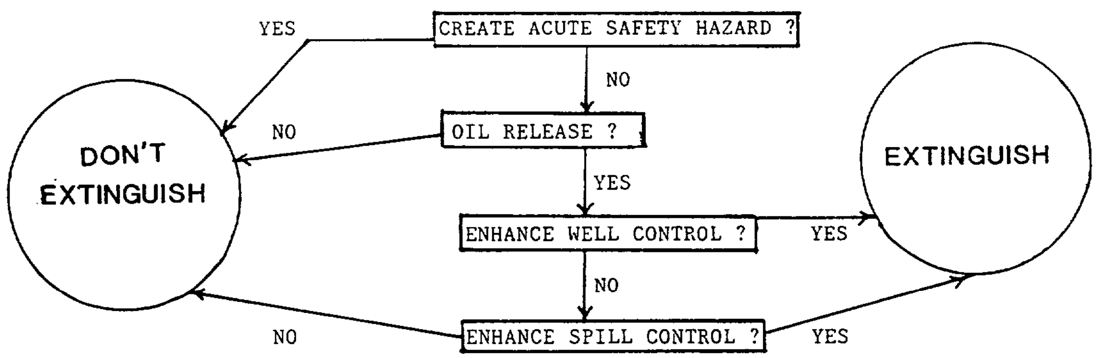
   * location of surface vessels near blowout
   * optimum location of relief wells
   * explosion/accidental ignition zones (Figure 3)
   * radiated heat (Figure 14)
   * subsea visibility
   * opinion of well control experts

4. Will extinction of the burning gas enhance spill control countermeasures?

* siting of recovery equipment
* potential for reduced emulsification
* loss of firelight for night-time operations
* no flashing of volatiles from oil

FIGURE 26

RELATIONSHIP AMONG CHECKLIST QUESTIONS FOR
EXTINGUISHING SUBSEA BLOWOUTS



CONCLUSIONS

Unless there is an acute hazard to human safety, igniting the products of a well blowout should only be used as a last resort spill countermeasure to prevent environmental damage. This action should only be taken after careful consideration of the many implications of igniting a well. Decision-making aids, in the form of check-lists, have been developed to assist on-scene commanders in collecting as much of the pertinent information as possible in order to make a logical, defensible decision on well ignition.

Unless a burning blowout can be extinguished quickly, the rig, well-head, control equipment and ancillary equipment will be severely damaged. In this case the option of extinguishing the fire should be taken only after careful consideration of the implications of this action. Decision-making aids, in the form of check-lists, have been developed to assist on-scene commanders in collecting as much information as possible in order to make a logical, defensible decision on extinguishing a burning blowout.

During the course of this study, the study team concluded that it was impossible to develop a decision-guide (implying a charted process resulting in a simple yes or no decision) for well ignition or extinction. The main reason for this conclusion is the unique nature of each blowout event and the impossibility of predicting, in advance or even during the incident, all of the factors that go into the decision-making process. The project team has concentrated on developing decision-making aids, in the form of check-lists, that help the decision-makers to evaluate the key factors and their implications. The decision-making process and the decision are left to those with the responsibility and authority.

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APPENDICES

APPENDIX I

ATMOSPHERIC GAS DISPERSION MODELLING

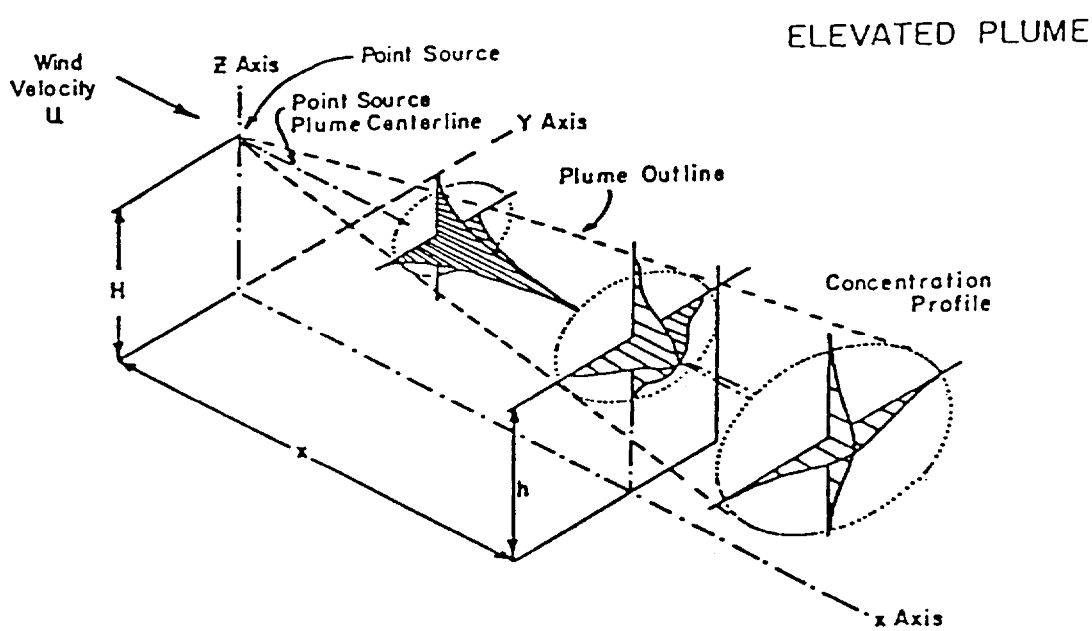
The near source concentrations of the gases released from the blowouts have been modelled to predict the extent of the potentially hazardous zone. The standard mathematical method of modelling these concentrations of gases is to assume that the gas cloud takes on a particular shape (Gaussian) and spreads according to experimentally determined horizontal and vertical dispersion coefficients (Turner 1970, Strauss 1971, and Stern 1976). Figure A1 describes this method pictorially. The rates at which the cloud spreads vertically and horizontally are the most important model parameters. Although these are quite variable and not well documented or understood especially over the open ocean, Turner has developed coefficients for different classes of atmospheric stability and has defined stability groupings in terms of wind speed and solar radiation.

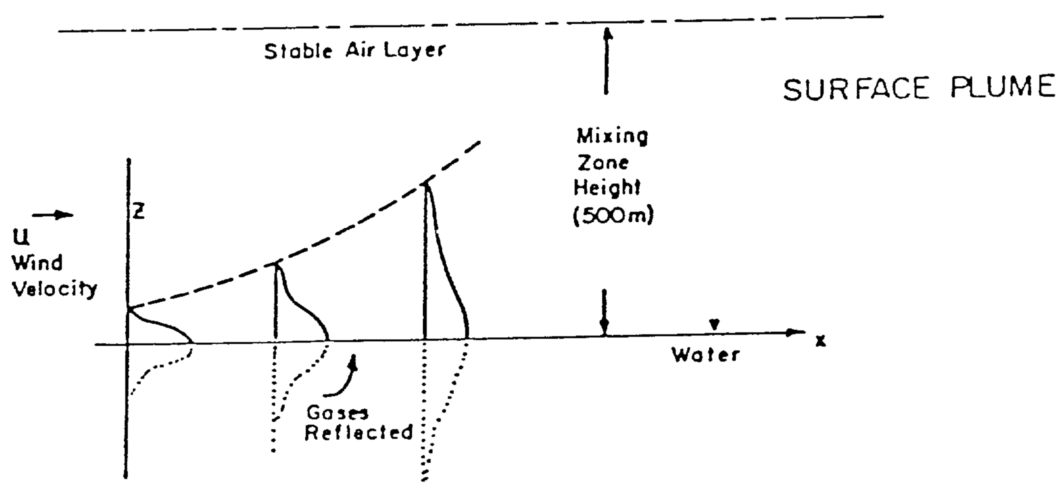
Several factors should be mentioned to clarify the assumptions inherent in the model used (refer to the lower diagram of Figure A1). The dotted lines are intended to indicate that any gas which diffuses to the water or ground surface is reflected back into the atmosphere and is not absorbed by the water. The model accounts for this reflection for the case of these gaseous releases.

Of less importance, for this type of release of gas, is the atmospheric mixing zone identified on Figure A1. The actual height of this layer varies greatly with geographic location. Any gas which reaches the maximum mixing zone height will not be mixed into the upper stable air layer but will instead be reflected back into the mixing region. For a surface discharge it is unlikely that the gas will occupy the full mixing height except in minute concentrations far downwind of the discharge. For platform blowout plumes which have discharge points high above the surface (see upper diagram of Figure A1) this phenomenon requires additional attention.

FIGURE A1

SCHEMATIC REPRESENTATION OF AIR CONTAMINANT MODEL





Under calm wind conditions the model used is no longer valid as the plume will simply billow up and out from a central location. This is of little concern since calm winds exist only for a very small percentage of the time.

APPENDIX II

SLICK DIMENSION MODELS

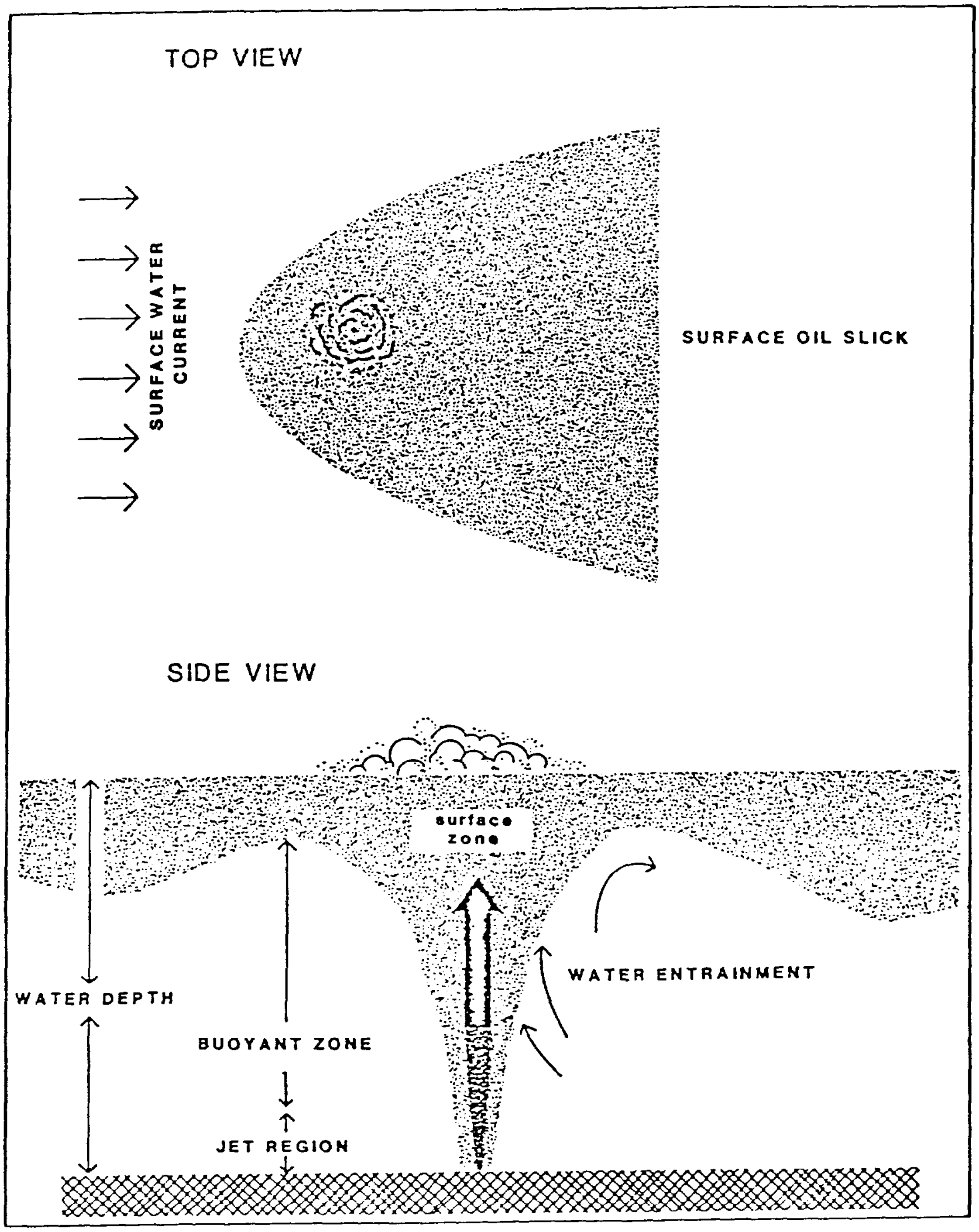
Subsea Blowouts

The oil and gas released from a subsea blowout passes through three zones of interest as they move to the surface (Figure A2). The high velocity at the well-head exit generates the jet zone which is dominated by the initial momentum of the gas. This highly turbulent zone is responsible for the fragmentation of the oil into droplets ranging from 0.5 to 2.0 mm in diameter (Dickins and Buist 1981). Because water is also entrained into this zone, a rapid loss of momentum occurs a few metres from the discharge location. In the buoyant plume zone, momentum is no longer significant relative to buoyancy which becomes the driving force for the remainder of the plume. In this region the gas continues to expand due to reduced hydrostatic pressures. As this large quantity of gas rises, the oil and water in its vicinity are entrained in the flow and carried to the surface waters.

Although the terminal velocity of a gas bubble in stationary water is only about 0.3 m/s, velocities in the centre of blowout plumes can reach 5 to 10 m/sec, due to the pumping effect of the rising gas in the bulk liquid. That is, the water surrounding the upward moving gas is entrained and given an upward velocity, which is then increased as more gas moves through at a relative velocity of 0.3 m/s, etc. When the plume becomes fully developed a considerable quantity of water is pumped to the surface.

In the surface zone, the rising water and oil flow away from the centre of the plume in a radial layer. At the surface the oil coalesces in ths outward flow of water and is spread into a slick at a rate much faster than conventional slick diffusion or spreading rates. The resulting slick takes on a parabolic shape when subjected to a natural water current, with its apex pointed up-current (Figure A2).

FIGURE A2 SCHEMATIC VIEWS OF A SUB-SEA BLOWOUT



Several researchers have studied experimentally and theoretically the fluid dynamics of such subsurface blowouts, namely, Fannelop and Sjoen (1980), Ditmars and Cederwall (1974), Topham (1975), McDougall (1978), and Hussain and Siegel (1976). The work of Fannelop and Sjoen has been used to model the Hibernia blowouts because it is easily adapted without extensive remodelling. The model has been validated by experimental data and by the contours of the slick formed during the Ixtoc 1 oil blowout. The problem with the use of this or any model is the selection of an appropriate water entrainment coefficient. We have chosen a coefficient value of $\alpha = 0.1$, as suggested by Fannelop. Also chosen was a value of $\lambda = .65$ for the ratio of buoyancy distribution to momentum or velocity distribution. An average surface current of 0.25 m/s was used in the model.

Above-surface Blowouts

Oil released during a blowout from a platform above the water's surface will behave quite differently than that from a subsurface discharge. The gas and oil will exit at a high velocity from the well-head and the oil will be fragmented into a cloud of relatively fine droplets. The height that this cloud rises above the release point will vary depending on the particle size distribution and the prevailing wind velocity. Based on limited data from actual incidents it is reasonable to assume that the cloud will rise to a point about 50 m above the water's surface (i.e., 25 m above platform). The fate of the oil and gas at this point is determined by atmospheric dispersion and the settling velocity of the oil particles. A slightly modified version of the atmospheric dispersion model described in the previous Appendix can be used to predict the behaviour of the gas and oil components as they move from the source.

Turner's dispersion coefficients have again been used in modelling atmospheric dispersion of the oil droplet cloud. The settling of the oil droplets has been accounted for by tilting the central axis of the plume at a slope determined by the fall velocity of the oil particle being modelled. The oil is also deposited at the water's surface and not reflected back as was assumed for the gaseous dispersions. The deposition rate of the oil at the plume centreline has been calculated by taking the product of the particle setting velocity and the centreline concentration. The oil settles out very quickly due to the relatively large drops which would be generated during such a release, and deposition of virtually all of the oil would occur within less than a kilometre downwind of the release, regardless of wind speed.

APPENDIX III

COMBUSTION EFFICIENCY MODEL

The basis for the burn efficiency model is a comparison of the droplet size distribution generated by the atomizing of the oil by the gas to the maximum diameter of oil droplet that can be completely burned in its residence time in the gas flame.

In order to find a maximum mean droplet size in the oil mist in the turbulent gas diffusion flame, which is able to evaporate completely in the flame, two length scales for the system were compared: one was the downstream distance from the pipe exit required to complete droplet vaporization, and the other was the length of the turbulent diffusion flame. It turns out that the maximum mean droplet diameter which ensures the complete combustion of the oil mist is given as follows, $\bar{d}_* = C(R/V_g)^{1/2}$, where C is a constant (10^{-2}), R is the pipe exit radius (m) and V_g the discharge velocity (m/s).

The combustion efficiency of droplets larger than $\bar{d}_*$ can be calculated from:

$$n_{ncb} \approx d/\bar{d}_*$$

where n_{ncb} = fraction of oil burned in droplets larger than $\bar{d}_*$
d = diameter of droplet (m)

This calculation is conservative since it is assumed that the oil is homogenous. The different boiling points of crude oil components may result in the explosion of oil droplets in the flame and thus better atomization and a higher removal efficiency.

In order to calculate the oil drop size distribution generated by a blowout the following calculations are required:

Gas Exit Velocity

$$V_g = Q_g\,(10/10+h)/\pi R^2$$

where Q_g = gas flowrate at STP (m^3/s)
h = water depth (m)

The value of V_g cannot exceed 517 m/s, sonic velocity in methane at STP.

Oil Exit Velocity

$$V_o = Q_o/\pi R^2$$

where Q_o = oil flowrate (m^3/s)

Two-Phase Flow Regime

$$V_{CHECK} = 17.7\,(Q_g\,(10/10+h)/Q_o)^{-0.96}$$

If $V_{CHECK} > V_o$ then annular flow doesn't exist and the droplet size model will not apply.

Sauter Mean Oil Drop Diameter

From the work of Deysson and Karian (1978) and Deysson (1978):

$$D_{sm} = (0.8/V_g)\,(\sigma/\gamma_o)^{1/2}\,(1 + 2.75\,(Q_o\,\gamma_o/Q_g\,\gamma_g)^{2/3})$$

Fraction of Oil Droplets Completely Burned

With a Rossin-Rammler drop size distribution (Deysson 1978).

$$n_{cb} = (1 - \exp(- 1/2\, (\bar{d}_* / d_{SM})^2))$$

Fraction of Oil Droplets Not Completely Burned

Assuming $D_{max} = 2.448\, d_{SM}$

$$n_{ncb} = (\pi/2)^{1/2} (\bar{d}_* / d_{sm}) (1 - \mathrm{erf}\, (\bar{d}_* / (2)^{1/2} d_{SM}))$$

Total Oil Burn Efficiency

$$n = n_{cb} + n_{ncb}$$

APPENDIX IV

MODELLING THE IGNITION OF A SOUR GAS WELL

Introduction

As already indicated, igniting a sour gas blowout reduces the toxic hazard of H_2S in two ways: most of the H_2S is burned, and any that is left unburned is dispersed from a greater height because of flame buoyancy. However, these benefits come at the price of a hazard from flame radiation.

In this section, these effects are calculated for the specific sets of conditions shown in Table 1.

Table 1
Conditions Examined

total flow 245,000 m^3/day = 2.836 m^3/s
Case 1 H_2S flow 0.37 m^3/s, rest CH_4
Case 2 H_2S flow 2.00 m^3/s. rest CH_4
In both cases three discharge diameters d_j were used
4" (10 cm), 8" (20 cm), 30" (75 cm)
In each case the gas temperature $T_j = 25^oC = 298$ K
and the ambient temperature $T_a = 5^oC = 278$ K

Calculated Parameters

Approximate calculations of the thermodynamic and flow parameters of the two cases produced the results shown in Table 2. These values were subsequently used in the calculations of the dispersion of the cold jet, the length of the flame when the jet is ignited, the dispersion of the combustion products, and the radiant heat flux from the flame.

Table 2

Thermodynamic and Flow Parameters

fraction of H_2S by volume		0.130	0.705
molecular weight of discharge, kg/mol		18.35	28.64
density of discharge gas, kg/m^3		0.750	1.17
discharge velocity, v_j m/s:	4" (10 cm)	361	361
	8" (20 cm)	90.3	90.3
	30" (76 cm)	6.25	6.25
mass flow of CH_4 -H_2S mixture, kg/s		2.127	3.318
lower heating value, cal/gm-mole		182,934	144,233
lower heating value, cal/kg		3.969×10^6	5.036×10^6
adiabatic flame temperature, K		2,200	2,096
discharge rate of H_2S in blowout jet, ug/s		5.52×10^8	2.981×10^9
fraction of heat release radiated		0.25	0.25

Dispersion of the Cold Jet

The first calculation was carried out for unignited jets. The equations used were the traditional equations developed in the 1960's and 1970's to describe the dispersion of stack gases from chimmeys and products of combustion from flares. The particular reference used in this work was the convenient summary published by Beychok (1979).

The first step in these calculations is to determine the rise Δh of the cold jet. The conditions of the calculations are shown in Table 3. Since the blowout is assumed to occur at the level of the platform (if offshore) or at grade (if on land), the effective stack height is the same as the rise Δh of the jet.

Table 3

Conditions of the Dispersion Calculations for Unignited Blowouts

wind speed u_∞ : 5 km/h = 1.39 m/s
and 30 km/h = 8.33 m/s

Pasquill stability conditions: A (very unstable)
and F (stable)

atmospheric stability parameter s for condition F: $8.81 \times 10^{-4}\ s^{-2}$

For Pasquill stability condition A, the equation for the maximum jet rise is

$$\Delta h_{max} = 3 d_j\, v_j / u_\infty \tag{1}$$

where

Δh_{max}	=	maximum rise of cold jet, m
d_j	=	discharge diameter, m
v_j	=	discharge velocity, m/s
u_∞	=	wind speed, m/s

For stability condition F

$$\Delta h_{max} = 0.95\, (T_a / T_j)^{1/3}\, u_\infty^{-1/3}\, s^{-1/6}\, (d_j\, v_j)^{2/3} \tag{2}$$

where the stability parameter $s = 8.81 \times 10^{-4}\ s^{-2}$

T_a	=	278 K is the ambient temperature
T_j	=	298 K is the discharge temperature.

The above equations apply equally regardless of the blowout composition. The results are listed in Table 4.

Table 4

Maximum Rise of Cold Blowout Jets

for both Case 1 and Case 2

Tabulated values are Δh_{max} in metres

Pasquill Stability Condition A

	u_{∞}, m/s	1.39	8.33
d_j, m	0.10	78	13
	0.20	39	6.5
	0.76	10.3	1.71

Pasquill Stability Condition F

	u_{∞}, m/s	1.39	8.33
d_j, m	0.10	30.0	15.1
	0.20	18.9	9.54
	0.76	7.77	7.13

The dispersion of these cold jets was examined by calculating the long-time average concentration of H_2S under the plume centreline at distances of 10 m, 100 m, 1,000 m, and 10,000 m downwind from the point of maximum plume rise - which is very close to the blowout itself.

The equation for this is

$$C = \frac{q}{\pi u_{\infty} \sigma_z \sigma_y} \exp\left(- \Delta h^2 / 2 \sigma_z^2\right) \qquad (3)$$

where

q	=	discharge rate of H_2S in the blowout, ug/s
C	=	ground-level concentration of H_2S, ug/m^3
u_∞	=	wind speed, m/s
σ_z	=	vertical dispersion coefficient, m
σ_y	=	horizontal dispersion coefficient, m
Δh_{max}	=	maximum plume rise, m.

The dispersion coefficients increase with increasing downward distance x. They take different values for rural and urban conditions. Rural conditions were assumed for this work. The values of σ are given by the following equation (Beychok 1979, pp. III-9, 10).

$$\sigma = \exp [I + J (\ln x) + K (\ln x)^2] \tag{4}$$

The coefficients are listed below.

Pasquill stability condition A

σ_z: I = 6.035, J = 2.1097, K = 0.2770

σ_y: I = 5.357, J = 0.8828, K = -0.0076

Pasquill stability condition F

σ_z: I = 2.621, J = 0.6564, K = -0.0540

σ_y: I = 3.533, J = 0.9181, K = -0.0070

The resulting values of σ are given in Table 5.

Table 5

Calculated Dispersion Coefficients

	Pasquill A		Pasquill F	
x,m	σ_z,m	σ_y,m	σ_z,m	σ_y,m
10	9.0	3.1	0.21	0.43
100	14.1	26.7	2.3	4.0
1,000	418	212	13.7	34.2
10,000	234,000	1,560	46.8	273

The value of σ_z at 10 km is obviously outside the range of validity of equ. (4).

The calculated values of ground-level concentration are tabulated for Case 1 in Table 6. The values for Case 2 would all be higher by a factor of 5.4. These values in $\mu g/m^3$ should be compared with 30 mg/m^3 = 30,000 $\mu g/m^3$ which corresponds to the U.S. Threshold LImit Value of 20 ppm for H_2S. H_2S represents a toxic hazard above the TLV.

Table 6
Calculated Ground Level Concentrations of H_2S
from Unignited Blowout Jets

C in $\mu g/m^3$

Note: All results are for Case 1. For Case 2 multiply by 5.4.

		wind speed 1.39 m/s		wind speed 8.33 m/s	
d_j, cm	x, m	stability A	stability F	stability A	stability F
10	10	0	0	265,000	0
	100	0	0	36,600	0
	1,000	1,400	24,900	240	24,500
	10,000	0.4	8,060	.06	1,570
20	10	360	0	583,000	0
	100	7,320	0	50,400	370
	1,000	1,430	104,000	240	35,200
	10,000	0.3	9,120	.06	1,620
76	10	4,500,000	0	745,000	0
	100	257,000	49,900	55,600	17,500
	1,000	1,430	269,000	240	39,200
	10,000	0.3	9,760	0.6	1,630

Evidently, H_2S is a potential toxic hazard in almost all of the cases studied.

Dispersion From an Ignited Blowout

The first part of this calculation involves calculating the length L of the turbulent diffusion flames produced when the blowout is ignited under various conditions. This part of the calculation follows the form presented by Becker and Liang (1978). The results are listed in Table 7.

Table 7
Flame Lengths of Ignited Blowout Jets

	Case 1	Case 2
d_j, cm	L, m	L, m
10	20.8	17.0
20	26.1	22.0
76	25.8	26.2

These flame lengths are remarkably similar under all conditions. They are calculated without reference to the wind. This turns out to be unimportant far enough downwind where the buoyancy of the combustion product plume is the major influence in the dispersion process.

The rise of the buoyant plume of combustion products is calculated by the methods developed for hot chimney plumes and adapted to flares (Beychok 1979, Ch. XI).

On the assumption that 25% of the heat released in the flame is radiated away, the buoyancy parameter F is 585 m^4/s^3 for Case 1 and 461 m^4/s^3 for Case 2. The plume rise depends on downwind distance up to a point and then remains constant.

For Pasquill stability condition A

$$\Delta h = 1.6F^{1/3}\,x^{2/3}\,u_\infty^{-1} \quad \text{for } x \quad < \quad \begin{cases} 1{,}520 \text{ m (Case 1)} \\ 1{,}380 \text{ m (Case 2)} \end{cases} \tag{5}$$

$$\Delta h_{max} = 38.7F^{0.60}\,u_\infty^{-1} \quad \text{for greater } x \tag{6}$$

For Pasquill stability condition F

$$\Delta h = 1.6F^{1/3}\,x^{2/3}\,u_\infty^{-1} \quad \text{for } x \quad < \quad \begin{cases} 86 \text{ m } (u_\infty = 1.39 \text{ m/s}) \\ 516 \text{ m } (u_\infty = 8.33 \text{ m/s}) \end{cases}$$

$$\Delta h = 2.4(F/us)^{1/3} \quad \text{for greater } x \tag{7}$$

The local plume height for dispersion calculations is taken to be the sum of the flame length and the local plume rise h. The calculations were performed for d_j = 20 cm. The results for d_j = 10 cm and d_j = 76 cm would be virtually the same because of the similarity of flame lengths shown in Table 7.

The local plume heights are shown in Table 8. These results are used together with equ. (3) to calculate the ground-level concentrations of H_2S.

The assumption is made that the combustion of H_2S is 95% complete. This reduces the source q by a factor of 20. If the combustion efficiency is actually 99%, the values shown in Table 9 should be reduced by a factor of 5. However, if the combustion efficiency is only 90%, they should be doubled. There are no data on the combustion efficiency of H_2S in such flames, but experience with H_2S flares in refineries shows that it must have a high value.

Table 8

Local Plume Heights for Ignited Blowouts

$$H = L + \Delta h, \text{ m}$$

(calculated for d_j = 20 cm, but very similar for 10 cm and 76 cm)

Pasquill Stability Condition A

		distance downwind of flame			
	u_j, m/s	x = 10 m	100 m	1,000 m	10,000 m
Case 1	1.39	70.8	233	985	1,300
	8.33	33.6	60.7	187	238
Case 2	1.39	63.3	214	911	1,130
	8.33	28.9	54.0	170	206

Pasquill Stability Condition F

Case 1	1.39	70.8	214	214	214
	8.33	33.6	60.7	129	129
Case 2	1.39	63.3	195	195	195
	8.33	28.9	54.0	117	117

It is evident from Table 9 that there is no H_2S hazard at the points where the calculation was done. The H_2S GLC's are negligible at most locations, and far below the TLV everywhere. This is the double effect of combustion and buoyancy. Even if the combustion efficiency were only 90% there would still be no hazard. A combustion efficiency of as little as 50%, an improbably low value, would produce a maximum GLC of only 1/3 of the TLV.

Table 9

Calculated Ground Level Concentrations of H_2S for Ignited Blowout Jets

C in $\mu g/m^3$

Note: All results are for d_j = 20 cm and a combustion efficiency of H_2S equal to 95%

		wind speed 1.39 m/s		wind speed 8.33 m/s	
	x, m	stability A	stability F	stability A	stability F
Case 1	10	0	0	34	0
	100	0	0	.3	0
	1,000	4	0	11	0
	10,000	.02	0.01	.003	1.8
Case 2	10	0	0	1,140	0
	100	0	0	10	0
	1,000	36	0	59	0
	10,000	.1	0.5	.02	19

APPENDIX V

FLAME LENGTH AND SAFE APPROACH DISTANCE MODELS

Flame Radiation

The radiation from the flame can be calculated by the point-source method used by the API and many others. In that method, the maximum radient heat flux at some distance D from the centre of the flame is given by

$$\dot{q}''_R = F\dot{Q}/4\pi D^2$$

where $\dot{q}''_R$ is the radiant heat flux, W/m^2

F is the fraction of heat release radiated

$\dot{Q}$ is the rate of heat release $= \dot{m} \times LHV$

$\dot{m}$ is the mass flow of burning gas, kg/s

LHV is its lower heating value, J/kg = (cal/kg) x 4.184

D is the distance from the flame centre, m.

Flame Length

Flame lengths are calculated using the methods of Brzustowski (1979) where the length of the flame is proportional to the radius of the exit cross-section.

These heat fluxes should be compared with 3.8 - 4.7 kW/m^2 (1,200 - 1,500 Btu/hr-ft^2) which is normally thought of as the limit of safe exposure for personnel for less than a minute in the absence of protective gear.