THE CONTROL OF RISK IN GAS TRANSMISSION PIPELINES

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This paper considers three aspects of risk control in UK gas transmission pipelines. Firstly, it considers the development of design criteria which aim to control risk by minimising failure probability and by defining routing and proximity criteria to limit risk to the public. Secondly, measures to monitor integrity are reviewed. These have the aim of maintaining low failure probabilities. Thirdly, the success of the above measures are judged in terms of failure probabilities and their consequences, leading to an estimation of individual and societal risks. The risks, so derived, demonstrate the acceptable safety of gas transmission in the U.K.

INTRODUCTION

Most hazardous chemical operations are carried out in the secure surroundings of an industrial site. The potential causes of plant failure can generally be identified as they are usually within the control of the operator, and the risk to the surrounding population can be calculated. Gas transmission pipelines differ in some respects because they pass through land which is not owned by the operator and to which the general public may have access. Thus a failure might involve members of the public. Design and operational strategies should therefore recognise these facts so that the risk to the public is minimised. For instance, mechanical interference by third parties is the major cause of gas transmission pipeline failures. Design considerations take account of the influence of pipe wall thickness on susceptibility to such failures, and operational considerations take account of the value of surveillance of third party activities in reducing their frequency; the consequences of any failure are controlled by pipeline route planning which minimises the population at risk. The success of such design and operating strategies can be judged by the fact that British Gas has accumulated over 200,000 km years experience of high pressure gas transmission pipeline operation and, apart from an incident during commissioning arising from a fault introduced during construction, there have been no major failures.

The safety record of British Gas transmission pipelines results from design and operational procedures recommended by a panel of the Institution of Gas Engineers (IGE). In addition to IGE members and British Gas

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representatives, this panel included external experts in related engineering disciplines. This paper reviews the engineering considerations which are the basis of the design and operational recommendations to control risk in gas pipelines. The paper then considers the risk to the public of a pipeline designed to these recommendations by quantifying the probability and consequences of failure.

IGE RECOMMENDATIONS

Background to IGE Recommendations

The original recommendations of the IGE for transmission pipelines (IGE Communication 674) was published in 1965 and relied on American experience. Since that time the recommendations have undergone a series of revisions to reflect accumulated experience and advances in pipeline technology, and the background to these revisions has been given by Knowles, Tweedle and van der Post(1). Essentially, the early recommendations defined stress limits for pipelines (expressed as %SMYS, specified minimum yield stress or the corresponding ratio, design/SMYS, termed design factor) according to the population density around the pipeline. The recommendations published in 1970 and 1977 (IGE/TD/1) incorporated an additional limitation of pressure to 24 bar for pipelines operated in suburban (S) areas in which the population density exceeds 2.5 persons per hectare (1 per acre). This criterion was based on limiting the consequences of failure because it was known, from world-wide experience, that no major pipeline failures had occurred at pressures below 24 bar. The concept of limiting consequences was also considered in the relaxation to permit higher pressure pipelines in S areas if they are completely surrounded by sleeves capable of withstanding the full line pressure.

In 1977, a further version of the design section of TD/1 (IGE/TD/1 Edition 2: 1977) introduced major changes in which risk is controlled by limiting consequences of failure and by reducing the probability of failure. It was recognised that a pipeline could be operated in an S area at 70 bar - the same pressure as a rural, R area (this has now been increased to 100 bar in the 1984 Consolidated Edition of TD/1) - provided that the probability of a rupture is negligible. The logic for this change was research which showed that whereas rupture was a possible mode of failure at design factors above 0.3, it is most unlikely below this level and therefore pipelines could be operated in S areas under these stress conditions irrespective of pressure. Consequently only a puncture need be considered when defining proximity distances for property in S areas (corrosion generally leads to pin-hole leaks which are less serious). Thus the consequences of failure could be uniquely related to design factor for the definition of R and S area classification. Pressure, therefore, had only a minor effect on consequences and did not play a role in defining area classification; its only effect was on permitted proximity distances.

The background to the choice of the design factor of 0.3 is now well documented(1-3). Research, involving burst tests on pipes containing defects with a wide range of geometries, was aimed at determining both the failure stress and the failure mode. Figure 1 shows the mode of failure related to the stress level/SMYS and also to the defect length, 2C, expressed as a function of pipe radius, R, and wall thickness, t. All ruptures occur at high stresses and/or long defects. Two important points are illustrated by the figure. Firstly, failure as a rupture is most unlikely at stress levels (design factors) below 0.3; secondly, the leak/rupture line for corrosion defects lies above that for other artificial defects. This is because the corrosion defects do not have the uniform depth of the artificial defects and consequently they tend to fail by leakage in situations where a rupture might be expected. Since real defects approximate, in cross section, to the shape of corrosion defects, the latter behaviour pattern provides an additional safety factor in the application of the 0.3 design factor rule.

The present recommendations may be summarised as follows. Rural, R, area design is based on the fact that a rupture is possible and pipeline routeing is chosen so as to maintain proximities from property which take account of this failure mode. S area design is based on the assumption that ruptures are unlikely and proximities are chosen which account for credible failure modes ie leaks and punctures. A similar policy to S area design can be used for violations of the R area proximities where the pipe wall thickness is increased to reduce the design factor to 0.3. However, wall thicknesses exceeding 19 mm are not required if the resultant design factor is below 0.5. This relaxation is based on two considerations; firstly, such wall thicknesses are only required to achieve low design factors with relatively large diameter pipe. Since the leak-rupture criterion is a function of diameter, it follows that, for a given length of damage, the criterion becomes increasingly pessimistic for larger diameters. Thus the stress level may exceed the 0.3 design factor generally applied to smaller diameters whilst maintaining a low rupture probability. Secondly, it is difficult for mobile machinery to inflict damage which is signficant in pipelines with a wall thickness of 19 mm.

Proximity Criteria

Turning now to the question of proximities to property, we can use our knowledge of potential failure modes to define the consequences and so set proximity distances. For operation in R areas, where the design factor may be up to 0.72, a rupture is a credible event and it is desirable that proximities should reflect such a failure. Experience of full scale rupture tests on pipes and actual failures in the USA led to the conclusion that a typical rupture will have a length of between 5 and 20 diameters, and that any flame will have dimensions set by the geometry of the trench so formed. For some years the Midlands Research Station and the Engineering Research Station of British Gas have been conducting experiments to determine the thermal radiation levels resulting from pipeline fires. These experiments simulated the trenches associated with both punctures and ruptures. Essentially, the aim of the experiments was to determine the emissive power of the flame and from this to relate the perceived radiation level as a function of distance from the failure and the flame size. Typically, the data is used to formulate predictive computer programs. These may be represented by a relationship of the form:

$$I \propto \frac{Pd^2}{x^n} \qquad (1)$$

where I is the perceived radiation level at a distance ,x, from the failure P is the pressure and d is the diameter of the orifice in the test pipe (P and d thus control the gas flowrate from the orifice and hence the flame size). The power n is generally in the range between 1 and 2 and varies according to the view factor of the flame.

For a rupture, the flowrate and flame size are dependent on the pipe diameter and also the time after failure due to depressurisation of the compressible gas. In deriving proximities account was taken of this decay and the distances were chosen to correspond to a radiation level of approximately $32kW/m^2$ ($10,000 BTU/ft^2h$). This criterion was not chosen as a safe level as it is known that it approximates to '1% lethality' after direct exposure for 10 sec [4]. It does, however, reflect a judgement which accounts for a) the very low frequency of ruptures, b) the possibility of escape to take cover from direct radiation and c) the fact that the majority of the population is indoors for most of the time. The maximum number of people which could be exposed to such radiation levels is controlled by evaluating the population density in a zone having a total width of 10 times the proximity distance. If the density, quoted earlier, is exceeded then the pipeline is assessed as an S area pipeline.

The result of the above type of analysis is proximity limits (see fig 2) for all pipe sizes and operating conditions defined using a common basis which reflects the consequences of failure. The proximities so derived for R areas are the largest currently used in Europe.

In S areas, where the design factor is limited to 0.3, the most likely failure mode is a puncture. Data from actual punctures suggest that the hole size is generally smaller than 80 mm diameter equivalent. Experiments in which the jets from punctures impact the walls of the trench (such momentum-destroyed flames yield the highest perceived radiation levels) were used to determine distances to the $32kW/m^2$ radiation levels. These distances were used as proximities for S areas in TD/1 (line B, fig 3).

For pipelines with wall thicknesses below 9.5 mm it was apparent, from data records, that larger holes than 80 mm could occur. Futhermore, since such wall thicknesses are generally restricted to small diameter pipe, complete severance is possible and consequently the proximities were chosen to correspond with those for rupture of a 150 mm diameter pipe in R areas (line A, fig 3).

Considerable experimental work has been undertaken by British Gas to determine the force required to dent and puncture pipes [1]. Wall thickness is the major factor in resistance to denting and puncture and it was concluded that pipe of 11.9 mm would have adequate resistance to the mobile excavation equipment normally used in S areas. Consequently, IGE/TD/1 Edition 2 required no proximity limitations for pipe of this thickness other than a nominal 3 m for access purposes (line C, fig 3).

Having determined the criteria for pipeline design which minimises the possibility of failure and which limits the consequences to the public of any failure, we now turn to measures to maintain the integrity of the pipeline during operation.

Condition Monitoring

It was originally thought that safe pipeline operation could only be guaranteed by a process of revalidation hydrostatic proof tests; indeed this procedure was embodied in early editions of IGE/TD/1. It was, however, recognised that such a procedure is impracticable and, as a result of advances in pipeline technology, the alternative is permitted of in-service condition monitoring by either instrumented internal inspection devices to detect defects or above ground monitoring to determine the condition of the protective coating. In contrast to hydrostatic testing which 'detects' significant defects as a failure at the time of the test, the new procedures involve continuing inspection with emphasis on the ability to sentence and repair defects while the line is in service.

The background to the British Gas philosophy of condition monitoring has been discussed in Ref 5. Essentially, the minimum requirement of a condition monitoring technique should be the defect 'detection' standard attainable by repeat hydrotesting to a hoop stress level equivalent to yield (ie SMYS). Defect significance studies allow us to quantify the defects which would be detected (ie fail) at such hydrotest levels, and Fig 4 summarises the results. A locus is shown for the defect size (length and depth) which could fail at a design factor of 0.72. For long defects the locus becomes asymptotic at a defect depth of 0.4 x wall thickness; the corresponding defect depth for failure at a hydrotest level of 100% SMYS is a factor of two smaller, ie 0.2 x wall thickness. For shorter defects, the critical depth for failure, both at a design factor of 0.72 and at the hydrotest level, increases.

The failure locus for the hydrotest level is thus the desirable minimum standard for in-service condition monitoring. If this standard is achieved then the safety factor during operation is related to the difference between the hydrotest and operation loci. The safety factor, in terms of defect size, is greatest for the longer defects which are potentially more serious because of their rupture failure mode. The safety factor gives a margin to allow for defect growth processes such as fatigue and corrosion during service. Condition monitoring procedures must therefore be repeated before defects grow to reach the failure locus for the operational stress level and a knowledge of the kinetics of defect growth is the basis for defining monitoring intervals.

Although some British Gas pipelines are pressure cycled to achieve some 'line-pack' storage, the permitted cycle stress range has been defined in IGE/TD/1 (1985) so that a defect which can survive the initial pre-service hydrotest will not grow, by fatigue, to failure during the design life (6). Fatigue is thus not relevant in setting condition monitoring intervals. Corrosion is a possible growth mechanism in the event of breakdown of cathodic protection. Growth rates can be either measured from laboratory studies or estimated from depth measurements of corrosion incidents during service. Pessimistic assumptions of corrosion growth rates in absence of cathodic protection lead to the conclusion that condition monitoring by in-service inspection at 5 year intervals would be sufficient to prevent corrosion failures. The interval would be extended further for thick-walled pipelines. Taking these factors into account and the possibility that defects can be introduced by mechanical interference during service, an inspection programme has been defined involving a priority rating according to:

a) the pipe's age, stress level, possiblity of external interference, and corrosion protection effectiveness.

b) the proximity to buildings in relation to the consequence of a hypothetical failure.

This programme involves condition monitoring at 2, 5 and 10 year intervals depending on the priority rating.

British Gas has developed in-service internal inspection devices which allow defect detection to a standard superior to that determined by the hydrotest locus of Fig 4. Furthermore, it is possible to determine defect sizes and their distribution, and thus give a 'fingerprint' of the defect population in a pipeline, changes to which can be observed by subsequent inspections. The performance specification for detection sensitivity of the on-line inspection device is shown in Fig 4. Whilst matching the standard determined by the hydrotest locus for long defects, on-line inspection is superior for short defects and this compensates for the reduced margin between the hydrotest and operation loci for these defects.

Internal inspection techniques are preferred for condition monitoring. However, they are not practicable on all pipelines, eg those of smaller diameters, and alternative procedures are used to monitor their condition by establishing the condition of the external pipe protective coating and the efficacy of cathodic protection. The basis is that corrosion and mechanical interference would be associated with breakdown of the protective coating which could then be detected by above ground monitoring procedures.

In addition to the requirements of condition monitoring, pipeline integrity is enchanced by other maintenance and surveillance activities. The British Gas policy of annual pipe-to-soil potential measurements and monthly checks of CP current flow is similar to that of the US NACE Federal Safety Standards and serves to minimise the possiblity of pipline corrosion. Surveillance involves yearly or half-yearly ground patrols and fortnightly aeriel surveys with the objective of detecting or interrupting excavation activities adjacent to pipelines. Aeriel surveys first detected about 50% of excavation activities. These activities are mostly the long duration activities such as building which are responsible for most cases of serious damage in pipelines.

We have seen how decisions have been taken for the design and routeing of pipelines and how condition monitoring procedures have been developed for ensuring integrity during operation. The success of these decisions in relation to the safe transportation of gas can now be judged by risk analyses.

RISK ANALYSIS

In developing TD/1 consideration was given to risk analysis in that decisions were taken to minimise failure probabilities and their consequences. The decisions were supported by estimates of risk. Subsequently, further experience of operating the transmission system has been accumulated and further data on consequences has been obtained. It is appropriate, therefore to review the risk of gas transmission in the UK in the light of this information, particularly as such analyses are required to comply with current health and safety legislation.

Risk is the probability of occurance of defined consequences. For its calculation we need to estimate the probability of a failure and to determine its consequnces.

The probability of failure may be estimated either from historical experience of pipeline operation or by an analytical technique using fracture mechanics and known defect distributions. Both these procedures will now be considered.

Failure Probability - Historical Data

Many difficulties surround the use of historical failure data, particularly if data from other countries is used. Firstly, design standards, particularly with regard to wall thickness and stress level, may differ; secondly, maintenance standards vary with time and from country to country; thirdly, the terrain and population density around the pipeline may differ; fourthly, criteria for reporting failures are not uniform. This latter point is worth emphasising. For instance, USA Federal regulations only require the reporting of major incidents involving death, serious injury or substantial third party damage in transmission pipelines operating above a design factor of 0.2. Similar problems occur if failure data from other product lines is analysed such as the CONCAWE data on oil pipelines. We conclude that the best data to use in probability analysis is histroical data from the system under evaluation.

British Gas has an extensive data collection scheme in which any incident, even if only the protective coating is removed, is recorded for pipelines operating above 7 bar. Information from this scheme for the period January 1969 to December 1977 was made available to the HSE for their report on the St Fergus to Moss Morran pipeline ([8]). 31 incidents involving loss of gas (excluding those due to corrosion) were apportioned according to the equivalent hole size to give the incident frequency as follows:

Hole Dia mm	No of Incidents	Frequency per km year
> 80	1	7.5×10^{-6}
20 - 80	3	2.2×10^{-5}
< 20	27	2.02×10^{-4}
		2.32×10^{-4}

The incidents with hole sizes below 20mm are generally small pin-hole leaks due to girth weld defects and fracture of small attachments and do not contribute a hazard. Note also that the single hole 80mm was the rupture during commissioning due to construction damage, referred to earlier, and is not representative of experience during pipeline operation. The conclusion from this data is that the incidence of significant failure is 22×10^{-6} per kmy and the incidence of major ruptures is less that 7.5×10^{-6} per kmy.

Since the Moss Morran report, British Gas has been further evaluating data and experience has now been accumulated of 220,000 kmy operation of transmission pipelines. Since there have been no ruptures during operation the incident rate from mechanical interference is:

Ruptures - less than 4.5×10^{-6} per kmy

To derive puncture rates we use information from 14 incidents involving pipe wall penetration in the period January 1968 - September 1983. This information, shown in the table below, is divided according to area classification, R and S, and wall thickness. The exposure in Km years is given and the failure rate for 10^6 kmy exposure calculated.

TABLE 1: MECHANICAL DAMAGE INCIDENTS INVOLVING PENETRATION

Wall Thickness	R Area	S Area	Total
$\leqslant$ 9.5 mm	11 106,610 103	2 11,074 180	13 117,684 110
$>$ 9.5 mm	1 90,023 11	0 13,744 -*	1 103,767 10
Total	12 196,633 61	2 24,818 80	14 221,451 63

KEY: *No. Incidents*
kmy exposure
Incidents, 10^{-6}/kmy

* If there had been one puncture in this category the incident rate would have been 73 x 10^{-6} kmy.

Two principal facts emerge from this data. Firstly, total penetration rates in R and S areas are not dissimilar; secondly, the penetration rates in thick wall pipe are an order of magnitude lower than in thin walled pipes. This conclusion supports the emphasis placed on wall thickness in IGE/TD/1 in determining S area proximities.

Failure Probability - Theoretical Prediction

The absence of ruptures implies that we cannot use historical data to evaluate the effect of design parameters and operational conditions on rupture risk. However, we can use analytical techniques based on fracture mechanics to statistically predict rupture rates in the following way. The British Gas data scheme, operated by the Engineering Research Station, collects information on the length and depth of all defects introduced by mechanical interference even though they do not fail. The data, shown in Figure 5, may then be statistically analysed to determine the probability that defects will exceed the failure locus. (Note that this form of analysis is pessimistic since it assumes that defects are flat-bottomed. This is not the case in practice and some defects will be stable even though the analysis would predict failure). This probability can be used to compute failure rates which can take into account design parameters such as pipe diameter and wall thickness and also operational parameters such as pressure. We can thus predict failure rates for any given pipeline.

A relevant point to consider from the analysis is the relative predicted rupture rates for pipelines operating in R areas in the permitted design factor range 0.5 to 0.72 with those in S areas restricted to 0.2 to 0.3 design factor. For example, the relevant rupture rates for 914 mm pipes are:

R areas	2.2×10^{-6} per kmy
S areas	0.26×10^{-6} per kmy

The predicted R area rupture rate is not inconsistent with practical experience of the British Gas system for which the rupture rate is less than 4.5×10^{-6} per kmy. The main point to note is that the S area rupture rate is an order of magnitude lower than for R areas. This confirms the philosophy of the TD/1 0.3 design factor recommendation, particularly when it is considered that the pessimistic assumption relating to uniform depth defects has a major effect in overestimating rupture rate predictions for S areas pipelines operating at this design facor.

Consequences of Failure

In predicting failure consequences we firstly need to determine the probability that a pipeline failure will result in a fire. A review of world-wide field failures suggests that the ignition probability is likely to be of the order of 0.5 for ruptures and 0.1 for leaks.

Consequences will depend upon whether individuals are exposed inside or outside buildings. The 2nd HSE Canvey Report(9) adopted a probability of 0.15 for outside exposure, i.e. 3.6 hours per day. 3.6 hours seems to be excessively high as we are concerned with the risk to an individual resident outside and in the vicinity of his own residence. An estimate of average "residence". times suggests that the probability of outside exposure is 0.03 (i.e. 0.8 h/day) and inside exposure is 0.6 (i.e. 15 h/day). These estimates take account of weather and absences due to work, shopping, school, holidays, etc.

There have been many assessments of hazard to the public as a result of thermal radiation (e.g. Ref 4,8,9). Radiation fluxes are quoted according to people being "at risk", subject to serious burns or a lethality level. Examples are as follows:

Canvey HSE Report(9)	Limiting 'safe' flux "At risk" 20s blistering 0.5 probability of taking cover 0.9 probability of taking cover	4 kW/m^2 12.6 kW/m^2 6.5 kW/m^2 6.5-12.6 kW/m^2 4 - 6.5 kW/m^2
Moss Morran (from API RP521)(8)	Tolerable level Death in 60s	1 kW/m^2 8 kW/m^2
F.P. Lees(4)	1% lethality (10s exposure) (45s exposure)	33.1 kW/m^2 10.2 kW/m^2

'Inside' hazard assessment is concerned with radiation effects on wood and fabrics. The Canvey report assumes that people indoors are at risk with a radiation level greater than 12.6 kW/m^2. This level is the same as that recommended for the derivation of safe separation distances between properties from fire spread considerations(10). It is suggested that this level is pessimistic for purely radiation risk assessment. A more appropriate threshold for inside risk would be 16 kW/m^2, a level approximating to that for cotton fabric ignition.

Taking the IGE/TD/1 proximity distance to correspond with a radiation level of 32 kW/m^2 and the expected radiation-distance relationship we may relate these consequence criteria to distance from the pipeline, expressed in terms of units of proximity distance. This is shown in Figure 6. The consequence bands correspond to radiation predictions using values of 1.6 and 1.3 for the parameter, n, in eq.1. (The lower figure is to account for the change in radiation-distance relationship when the flame dimensions are significant compared with the distance from the flame.) The general conclusion from the figure is that persons exposed outside are at risk up to distances of between 3 and 4 proximities from a failure; survival within this zone is related to the ability to escape or take cover. Indoor risk becomes apparent within 2 proximities. It should be noted that survival within these limits is demonstrated by study of failures in the US. Additionally, following a recent rupture in Germany, the occupants of a house at a distance 1 to 1.5 "TD/1 proximities" from the failure escaped unharmed. The house was not burnt lending support to the threshold radiation for ignition of buildings proposed in Figure 6. Analysis of casualty risk and the ability to take cover has now been computerised by the British Gas Midlands Research Station.

The consequence analysis reviewed here confirms the assumptions of IGE/TD/1 where the population density in R areas is assessed within a band 5 proximity distances each side of the pipeline, thus limiting the number of people at risk. Figure 6 shows that all consequences are contained within this boundary.

Individual and Societal Risk Estimation (R Areas)

We may now use the probability and consequence data to estimate both individual and societal risk. The individual risk is given by the following:

$$I.R. = P_f \times P_r \times P_i \times P_e \times P_c$$

where P_f = Probability of failure

P_r = Probability of interaction of failure with property

P_i = Probability of ignition

P_e = Exposure probability, i.e. indoor plus outdoor residence duration

P_c = Probability of being a casualty

If we consider the occupant of a property situated in an R area at the TD/1 proximity distance from a pipeline and pessimistically assume that the occupant is a casualty for any failures which occurs over a total distance of 2 proximities along the pipeline, we get:

$P_c = 1$

$P_r = 2 \times$ TD1 proximities per unit length*
$= 2 \times 77$ per km for a 914 mm pipeline

$P_f = 4.5 \times 10^{-6}$ per kmy for a rupture, from section on probabilities (ie upper bound)

Thus,

$$IR = \frac{4.5 \times 10^{-6} \times 154 \times 0.5 \times 0.63 \times 1}{10^3}$$

$$= 0.2 \times 10^{-6} \text{ per year.}$$

A similar calculation for S areas for a property on the proximity of a pipeline thinner than 9.5 mm yields an individual risk, using the probability data of Table 1, of

0.36×10^{-6} per year.

The corresponding figure for pipelines of thickness equal to or greater than 9.5 mm wall would be an order of magnitude lower than this, because of the lower incident rate.

The individual risks to the residents of properties bordering the pipeline are very low and should be considered in context of the pessimistic assumption of the casualty probability of one per incident. (The implication here is that the same individual risk would be applicable if properties were situated within the TD/1 proximity.) The values may be compared with maximum individual risks of 67×10^{-6} per year computed for Canvey(8). In addition, the safety review of the Morecambe Bay gas pipeline and control reception terminal carried out by the Safety and Reliability Directorate(11) yielded maximum individual risks of 2×10^{-6} per year and 3.2×10^{-6} per year for the pipeline and slug catcher, respectively; these values, an order of magnitude higher than those calculated in the present paper, were accepted as a basis for granting planning approval by the Barrow Planning Committee.

The individual risks calculated in the present paper may be viewed in relation to the proposals of the Royal Society Study Group on Risk Assessment(12). They suggest that, where only a proportion of inhabitants of the country are at risk, a value of 10^{-6} per year is appropriate, and no further control (i.e. attempts to improve safety) are justified below a level of 0.1×10^{-6} per year. We believe the individual risk from pipelines to be about this level.

* This assumes that all failures along a length of pipeline interact with property where the distance from failure to property is less than $\sqrt{2} \times$ proximity distance.

Societal risk requires the integration of risks experienced by the population resident outside proximity boundaries. It involves analysis of casualty risk and of the ability to take cover, and sophisticated computerised techniques have been developed for this purpose by the British Gas Midlands Research Station. A simple estimate of societal risk may be derived using the rupture and puncture probabilities derived from British Gas experience and by making the pessimistic assumption that all residents of properties situated between 1 and 2 proximity distances from the pipeline would be casualties. Considering, firstly R areas, the total length of pipe larger than 300 mm diameter is approximately 5000 km. Combined with the rupture probability of less than 4.5×10^{-6} per kmy and the ignition probability, this leads to a societal risk of 10×10^{-3} per year. The number of people at risk, assessing the maximum population density permitted in TD/1 for R areas and the appropriate proximity for a 900 mm diameter pipe, is 5. (This pessimistically assumes that all failures involve this number of casualties; however, we know that the average population density is much lower than the permitted maximum so that the average casualties will be below this figure.) It is, of course, possible for the population density to locally exceed 2.5 per hectare. An upper limit would be the density for S areas, say 100 per hectare, in which case the potential number of casualties would be 88. In practice this is an unlikely situation as TD/1 recommends that such a concentration of population would cause the pipeline area to be reassessed as an S area, irrespective of the average population density determined over a strip 1.6 km along the pipeline and 10 proximity distances wide. However, in order to derive a societal risk for this situation we propose to use a probability 1×10^{-3} per year for 88 casualties. The pessimistic nature of this assumption can be judged from USA evidence from 21 rupture failures which ignited and the maximum number of fatal casualties in any failure was 17. For 1500 km of pipeline in S areas we derive a societal risk, also, of 10×10^{-3} per year for punctures, however, the number of people at risk is only 3 for a typical population density of 100 per hectare.

The societal risks obtained by the above simple, but pessimistic analysis may be put into perspective by comparing with other quoted societal risks. For example, the societal risk for 10 casualties is 10^{-3} per year for the one industrial site at Canvey, alone.

Societal risk data has been published in the form of frequency-consequence lines(12). This information is shown in Figure 7 in which the positions of the societal risks for R and S area pipelines are indicated. The conclusion is that the societal risk for pipelines compares favourably with other activities. Additionally, they are well below the envelope, shown in Figure 7, which was proposed by Lees(13) as a limit which should be achieved by all UK chemical process plant.

CONCLUSIONS

The background to the derivation of pipeline design and routeing criteria and the procedures for monitoring in-service integrity have been described. Simplified calculations, making pessimistic assumptions, of individual and societal risks demonstrate the acceptable safety of gas transmission lines in the UK and they vindicate the risk control measures in design and maintenance.

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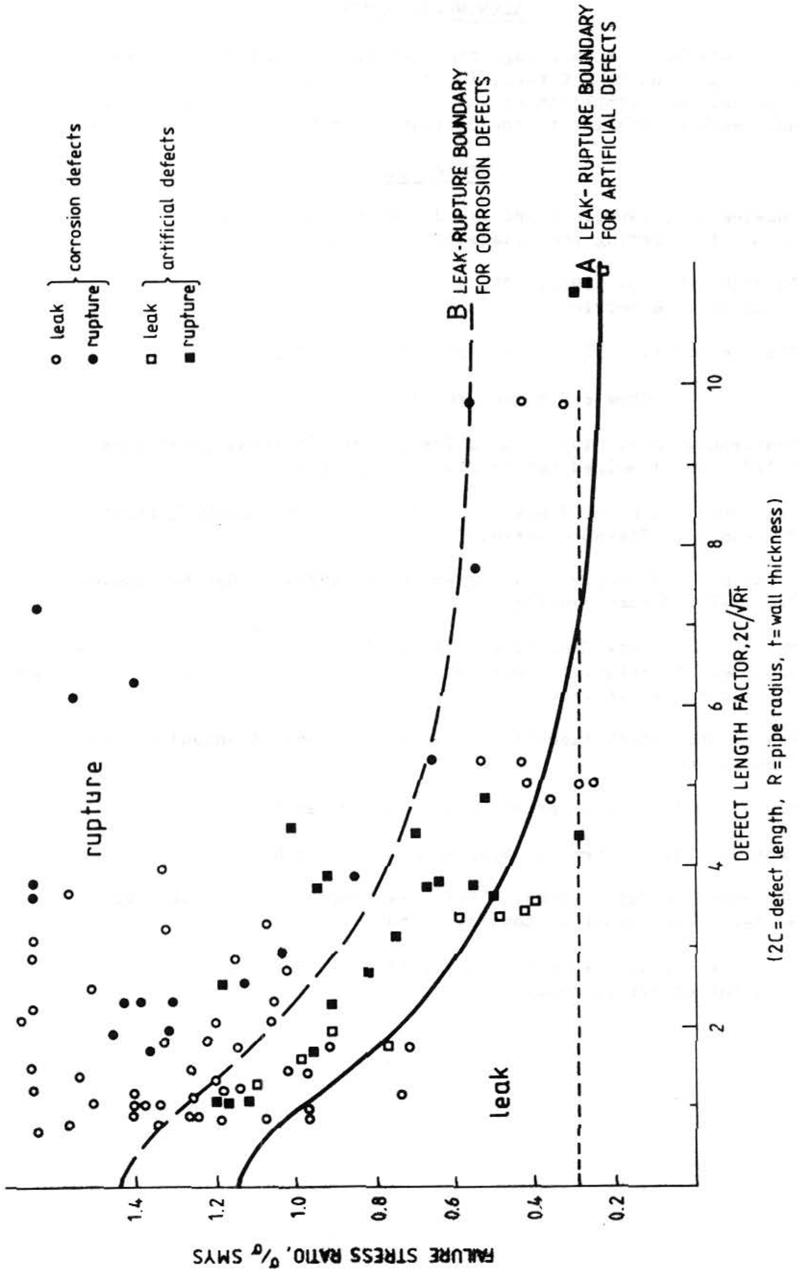

FIG.1 : LEAK-RUPTURE BEHAVIOUR OF PIPELINE DEFECTS

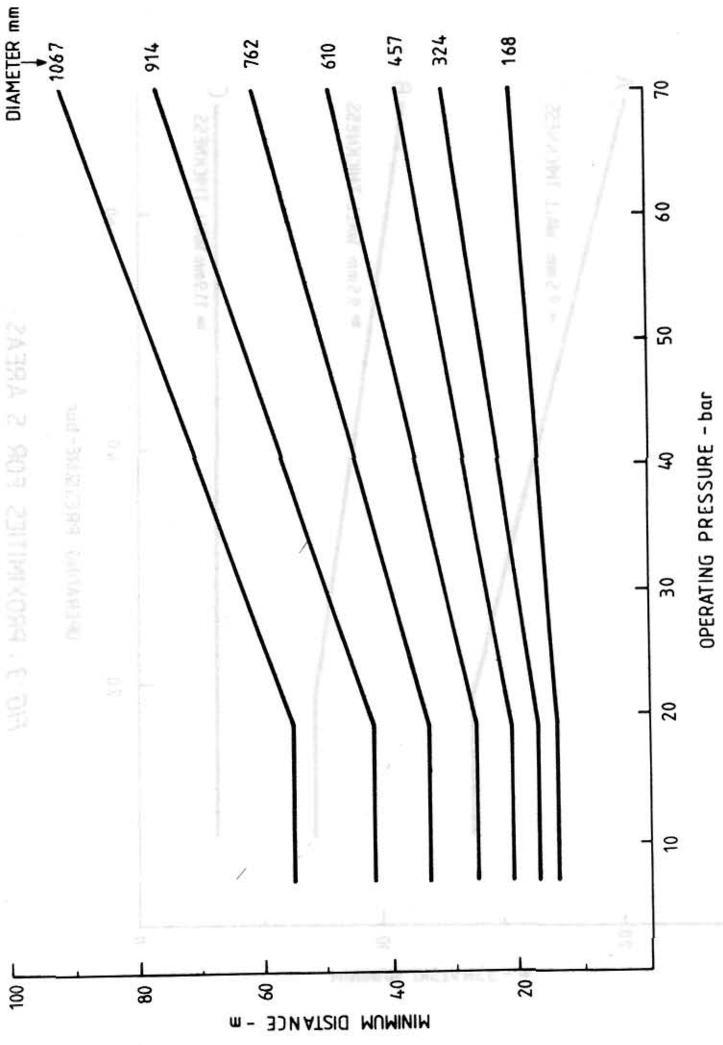

FIG. 2 : PROXIMITIES FOR R AREAS

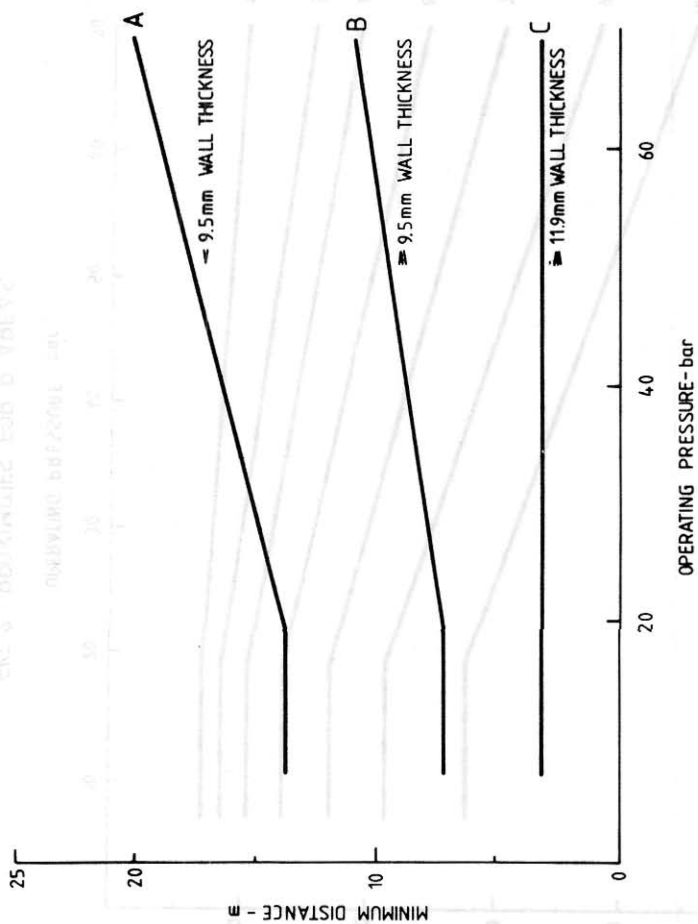

FIG. 3 : PROXIMITIES FOR S AREAS

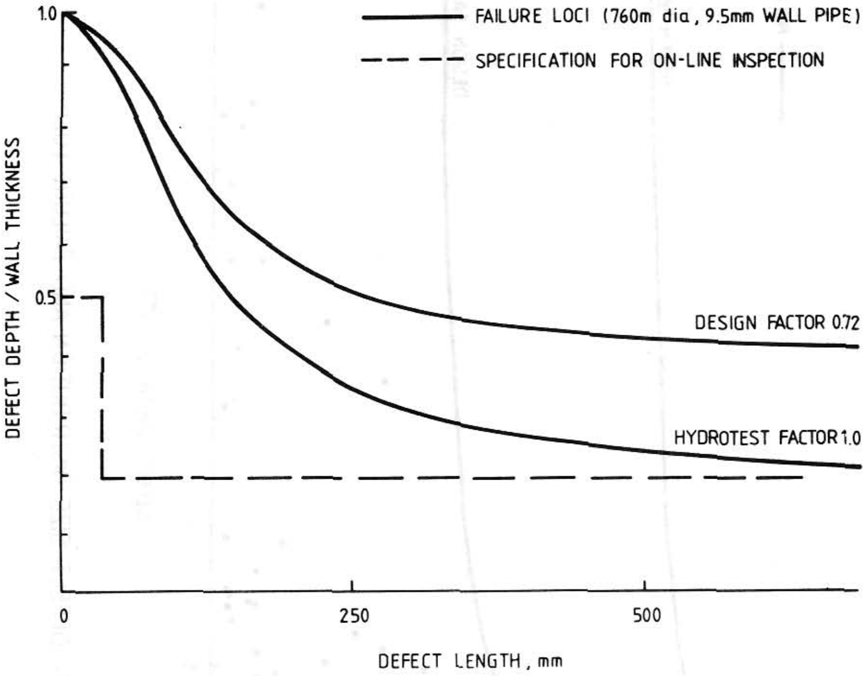

FIG.4 : DEFECT FAILURE LOCI AND SPECIFICATION FOR ON-LINE INSPECTION SENSITIVITY

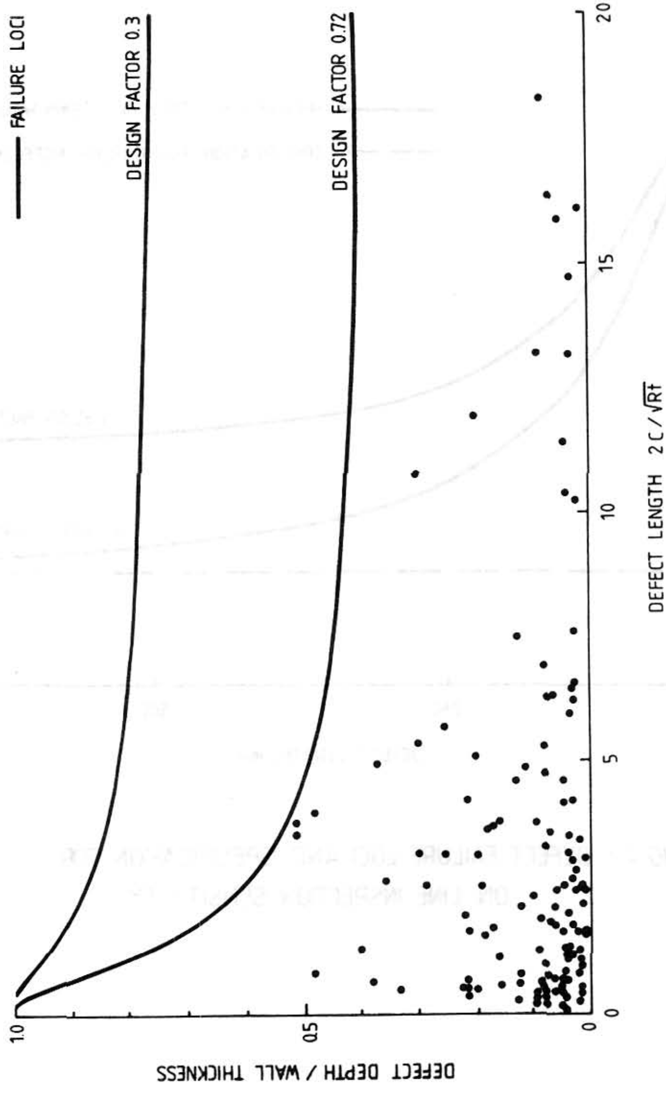

FIG. 5 : DEFECT SIZE DISTRIBUTION AND FAILURE LOCI

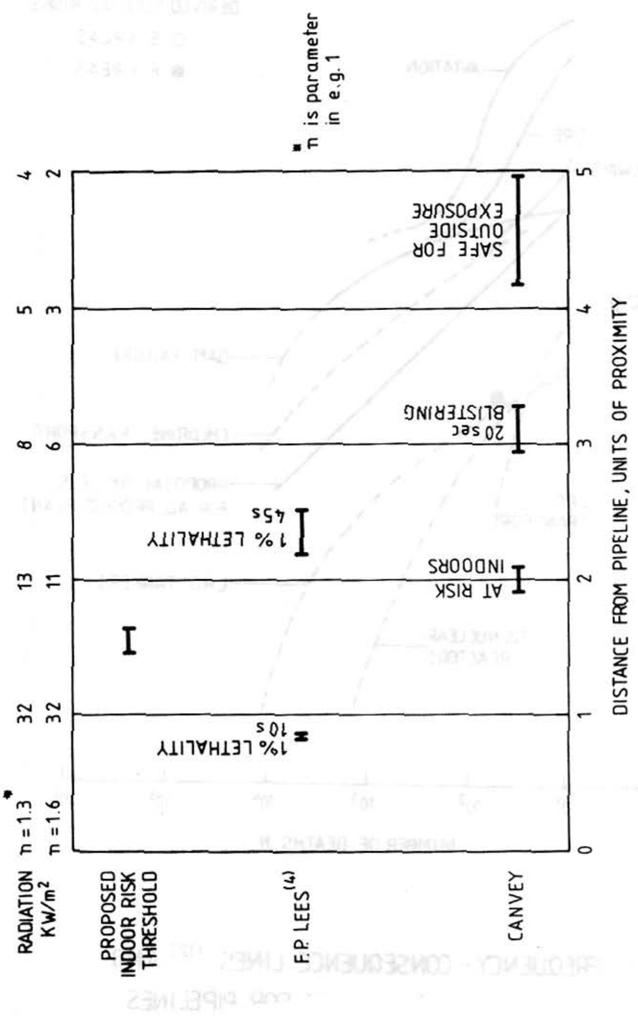

FIG. 6 : CONSEQUENCES AS A FUNCTION OF RADIATION AND DISTANCE FROM FAILURE

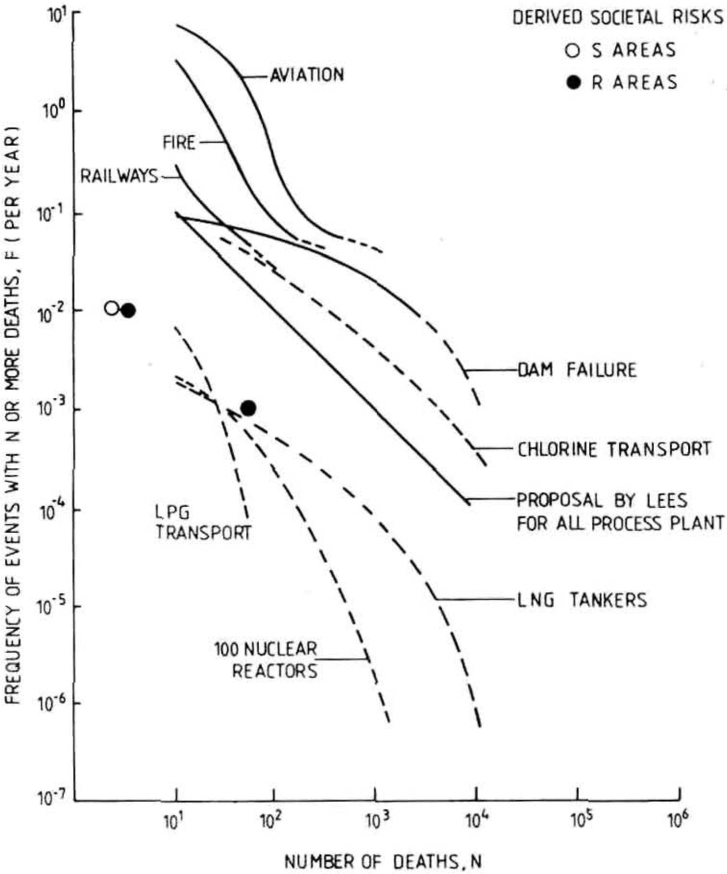

FIG. 7 : FREQUENCY - CONSEQUENCE LINES [12] AND DERIVED SOCIETAL RISK FOR PIPELINES