UNION OF
CONCERNED
SCIENTISTS

May 5, 2000

Mr. Christopher Grimes, Chief
License Renewal and Standardization Branch
United States Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: CANDIDATE REFERENCES FOR GENERIC AGING LESSONS LEARNED

Dear Mr. Grimes:

During a December 6, 1999, public meeting on aging management, I contended that the NRC's generic aging lessons learned (GALL) program did not encompass reports on aging prepared by UCS and others. You asked me if the subject reports had been submitted to the NRC. I responded by saying that I expected so, but could not be sure without checking. In any case, I committed to providing you with a list of these GALL candidate references.

Since December, you have reminded me several times of my commitment and asked me for the references. I have no valid excuses for the delay, but here is the listing:

- H. M. Thomas, Rolls-Royce & Associates, "Pipe and Vessel Failure Probability," *Reliability Engineering*, 1981.
- Nicholas T. Saltos, Probabilistic Safety Assessment Branch, Nuclear Regulatory Commission, "Risk Impact of Environmental Qualification Requirements for Electrical Equipment at Operating Nuclear Power Plants," March 30, 1993.
- Robert Pollard, Union of Concerned Scientists, "US Nuclear Plants - Showing Their Age / Case Study: Core Shroud Cracking," September 1995.
- Robert Pollard, Union of Concerned Scientists, "US Nuclear Plants - Showing Their Age / Case Study: Reactor Pressure Vessel Embrittlement," December 1995.
- Robert Pollard, Union of Concerned Scientists, "US Nuclear Plants - Showing Their Age / Case Study: Steam Generator Corrosion," December 1995.

Copies of these references are enclosed. The three UCS reports are copyrighted. You have our permission to place copies of these reports in the NRC Public Document Room/ADAMS.

Sincerely,

David A. Lochbaum

David A. Lochbaum
Nuclear Safety Engineer

Washington Office: 1616 P Street NW Suite 310 • Washington DC 20036-1495 • 202-332-0900 • FAX: 202-332-0905
Cambridge Headquarters: Two Brattle Square • Cambridge MA 02238-9105 • 617-547-5552 • FAX: 617-864-9405
California Office: 2397 Shattuck Avenue Suite 203 • Berkeley CA 94704-1567 • 510-843-1872 • FAX: 510-843-3785

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Enclosure 3

To: Don Dorman (30 copies), Mike Mayfield (1 copy), Fred Simonen (1 copy), Bill Pennell (1 copy)
FROM: Bob Carter, John Haseltine (Yankee Atomic Electric Company)

(Being provided in response to a 1/23/92 meeting commitment.)

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Reliability Engineering 2 (1981) 83 124

PIPE AND VESSEL FAILURE PROBABILITY

H. M. THOMAS

Rolls-Royce & Associates Ltd.
PO Box 31, Raynesway, Derby DE2 8BJ, Great Britain

(Received: 4 December, 1980)

ABSTRACT

This generalised approach to the estimation of failure probability is based on a pragmatic and scientific analysis of actual service failure statistics. Approximation strategies have been devised in order to estimate failure probability at the leakage level P_L *and for rupture* P_C.

P_L *is estimated from global statistics for leakage failure by using an observed correlation that a geometric proportionality measure of size and shape and weldments gives a direct measure of failure probability. This is the most powerful single influence of all in the determination of* P_L*, but the influence of plant age is also worth considering. The estimate may then be scaled for other factors if their influence is known.*

P_C *may be estimated given a* P_L *estimate, partly by using a fracture mechanics model which gives a carpet of* P_C/P_L *curves. Observed statistics are also used.*

NOTATION

A	Developed area
B	Design learning curve factor
D	Mean diameter
F	Plant age factor
K_c	Fracture toughness
L	Length
N	Number of cycles
P	Probability
P_c	Probability of catastrophic rupture

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P_{CD} Probability of a critical defect
P_L Probability of leakage failure
Q Size and shape factor of failure risk
Q_e Total equivalent size and shape factor
Q_p Q for parent material
Q_w Q for weld material
R^2 Statistical test
S Fatigue stress
Yr Year
b Crack proportion
c Critical crack half length—(in)
d_s Specimen diameter
$f(t)$ Function of t
l_s Specimen length
t Wall thickness
x An index for t
α Standard deviation
μ Mean
$\alpha(\sigma_c)$ Standard deviation for σ_c, etc.
$\mu(k_c)$ Mean of k_c, etc.
$\sum$ Sum of

INTRODUCTION AND OBJECTIVES

Plant safety and reliability are increasingly being considered in a probabilistic way; and there is a growing need to be able to make estimates of plant failure probability.

Various levels of failure may be identified, as in Table 1; together with an indication of the probability of detection and the consequences.

TABLE 1
THE LEVELS OF FAILURE AND THE CONSEQUENCES

Level of failure	*Detection probability*	*Consequence*
Minor defect	Low	Trivial
Serious defect	Modest	Potential danger
Through wall leak failure	High	Urgent warning
Rupture	Very high	Accident

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The probability of a small leakage failure P_L and the probability of rupture P_C are both required separately because they have different safety implications. P_L is a highly detectable warning of danger; P_C, on the other hand, may be the start of an accident chain.

This paper describes an approach to estimating P_L and P_C which is different from the usual mathematically based methods in the literature.

The objectives being pursued may be seen in the next section which lists the main attributes claimed for this modelling system. It may be seen to be pragmatic but scientific in its objectives and approach conforming with the basic principles of mathematical modelling.

The main body of this paper is a description of the modelling system and its possible use. It is meant to give an overall perspective and the broad strategies used. Appendices and reference material are used to derive and validate various factors: and to outline the supporting statistical evidence available.

ATTRIBUTES AND OBJECTIVES OF MODELLING SYSTEM

1. P_L and P_C are separately identified and the model applies to discrete parts and features of a plant.
2. It recognises the relative importance of the various factors involved and a first approximation is based on the most significant factor. The input data required for this is readily available, and all the calculations are easily and rapidly made by hand.
3. The approach is based on observed service failure statistics and recognises the multiplicity of failure causes and modes. The first approximation does not require the analysis of any particular one, such as fatigue.
4. Each factor which is modelled is scaled with a dimensionless ratio or group and each is separately amenable to statistical validation.
5. The whole approach, being modular and flexible, is capable of continuous and piecemeal improvement and development. Estimates based on it may be readily updated with the growing wealth of statistical data.

   The approach makes it possible to use all the statistical information which is available about various aspects of failure probability. It also provides a broad and comprehensive framework which can incorporate more detailed but incomplete models.

THE RELATIVE IMPORTANCE OF THE MAIN FACTORS

One of the pre-requisites of a mathematical model is a recognition of the principal factors involved, their relative importance, and their interrelationships if any.

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Many factors combine to determine the failure probability of some plant, some system, a pipe or just a feature such as a length of weld. Table 2 lists the main factors involved together with a rough estimate of their relative importance. This is the number of decades of variability of failure probability, which is generated by the usual range of variability of that factor as encountered in normal service. These decade estimates may be deduced from the statistical data referenced later in the report and appendices.

TABLE 2
FAILURE PROBABILITY DETERMINANTS AND THEIR RELATIVE IMPORTANCE

Factor	*Decades of influence*
Size and shape	$3\frac{1}{2}$
Weld zone risks	$1\frac{1}{2}$
Age factors	1
Quality factors	2
Failure causes and modes—fatigue, corrosion, erosion, etc.	$2\frac{1}{2}$
Rupture on leakage	4+

Several comments are worth making at this point about the nature of the problem of estimating plant failure probability.

The first point to be made is that the 'size and shape and weld zone' risk factors must be evaluated before any meaningful estimate is possible. These are a measure of the total opportunity to fail regardless of failure causes or modes. They must appear as the first term in any evaluation. It will be shown later that they are amenable to analysis to determine their risk potential.

It is also worth noting that age factors exert an inevitable influence on failure probability. Although they are less significant they are also amenable to estimation.

The statistical influence of quality factors is less well known as yet, but may prove to be amenable to modelling in time. The estimated influence of two decades is possibly too high. It is based on limited factual information.

The two-and-a-half-decade influence for the combined effects of failure causes and modes is also based on sparse data. These factors will probably remain as the most difficult to evaluate statistically; some very sophisticated mathematical modelling is to be found in the literature, particularly on fatigue failure. In spite of this some high technology industries suffer unexpected crops of fatigue and stress corrosion cracking failures, etc., none of which were predicted before the event.

These considerations lead one to conclude that there are severe limitations to the potential accuracy of any prediction. The state of the art is numerically still in the order of magnitude phase. Any attempt at probability modelling must recognise this. Sophisticated detailing must be avoided in favour of a 'broad brush' assessment.

The approach to the problem of failure probability modelling which follows, is based on the foregoing background.

THE BROAD STRATEGY

Figure 1 shows a broad approximation strategy which is envisaged in order to approach the general problem of estimating vessel and component failure probabilities. The probability of catastrophic leakage P_c is considered to be a subset of the more general leakage probability P_L; and since it is possible to estimate P_c/P_L, then P_c may be determined, given an estimate for P_L. There are many possible approaches to estimating P_L, including the direct observation of statistics for service failures.

Figure 1 shows an approach for P_L which first identifies a global estimate based simply on size, shape and weldment factors (Q_e) and modified by the influence of age (F). These factors may relate a component to some large known data base, Q_e being the most powerful factor of all. This global estimate may then be modified to specific plant factors including the influence (B) of learning curves for a given technology and design; and any failure risk improvement factors due to quality. More precise

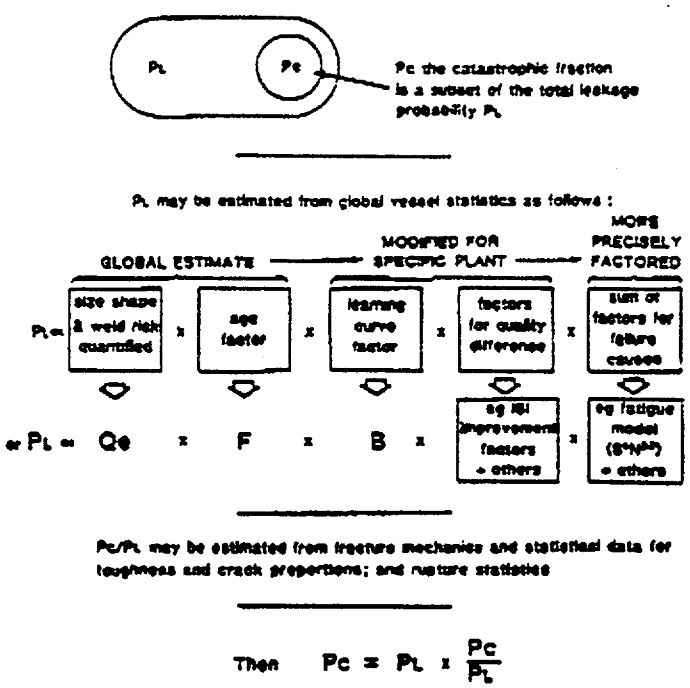

Fig. 1. The overall approximation strategy.

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estimates then become feasible by modelling the influence of all the known failure modes such as fatigue, stress corrosion cracking, etc. The modified global estimate may be factored up or down according to the sum effect of all the factors for the various failure causes. An earlier fatigue model ($S^5N^{2 \cdot 2}$) is an example of one such factor.[1]

P_C/P_L may be estimated by using some statistics for actual rupture cases; and by using a fracture mechanics model. The overall estimate for P_C/P_L is the sum of several categories of rupture causes which may be identified.

The factors identified on Fig. 1 are each discussed in the following text.

THE GLOBAL ESTIMATE FOR P_L

A first approximation to the leakage failure probability of a component may be made by using the following elements:

(a) A quantifier Q which evaluates the change in risk due to size and shape differences.
(b) Applying a $\times 50$ penalty to the quantifier for weld zones.
(c) A scaling factor F to correct for the influence of plant age.
(d) The average or global leakage failure rate for typical plant quantified as above.

(a), (b) and (c) Give a measure of the total opportunity to fail and (d) gives the failure rate. Using a 'weak link' analogy, these opportunities to fail, or risk units, are like the links of a chain. Failure probability is directly proportional to their number.

The chosen measure for the influences of size and shape on failure risk is $Q = DLt^{-2}$. This is a dimensionless quantity which correlates well with failure risk. Appendices 1 and 2 fully discuss this choice of quantifier, and show the statistical justification for it. Q_p refers to parent material. Q_w refers to weld zone material. The weld zone is arbitrarily defined as being $1 \cdot 75t$, and this definition requires a $\times 50$ penalty for the additional failure risk in that zone. This topic is discussed in Appendix 3.

For components with a mix of parent and weld zone material the equivalent risk $Q_e = Q_p + 50Q_w$. Leakage failure rates are typically in the range of 10^{-7} to $10^{-9}/Q_e$ Yr, i.e. $P_L \sim 10^{-8}/Q_e$ Yr.

This assumes a constant annual failure rate regardless of age, which is not quite true; but it is a reasonable approximation. Appendix 4 shows that typically the annual failure rates for plant fall by a factor of about five from the first to the twentieth year.

Figure 2 gives a typical average curve for the factor F. F is the cumulative failure probability expressed non-dimensionally as a fraction of the 10 years of age cumulative failures.

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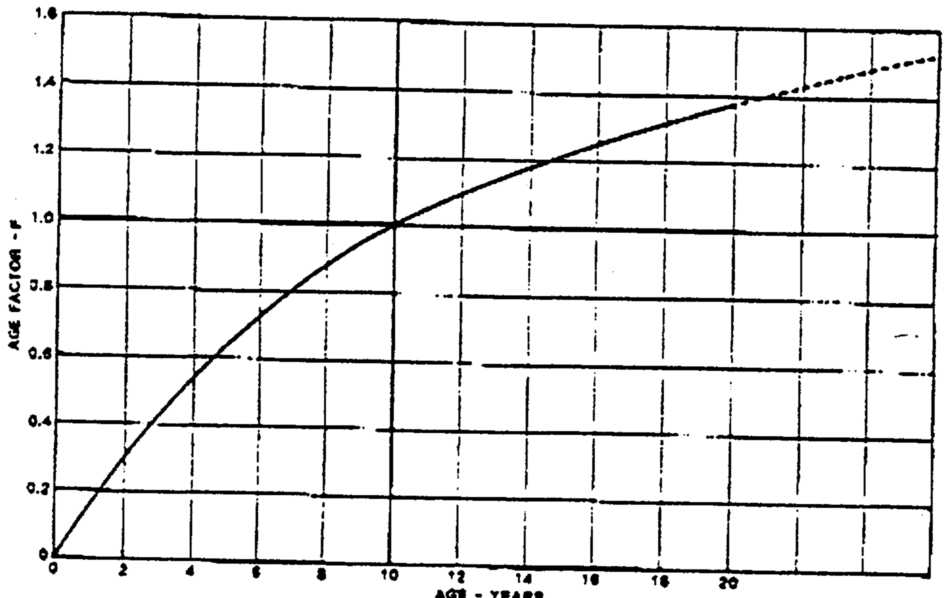

Fig. 2. A simple arithmetic average of all the various age factors.

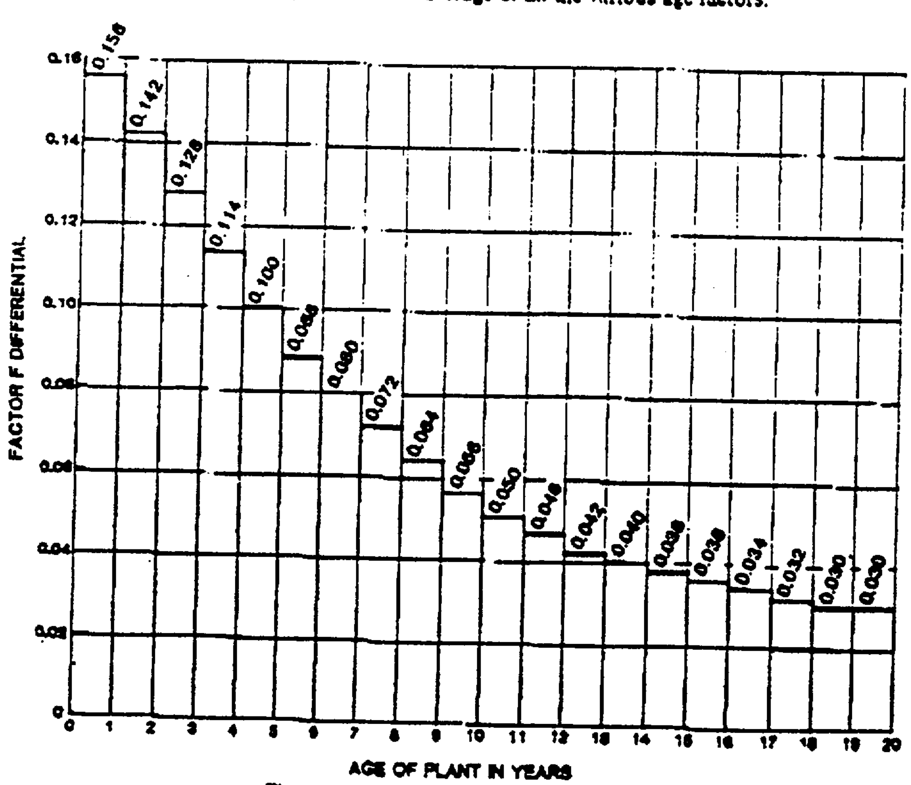

Fig. 3. Factor F differential.

More precisely then

$$P_L \sim 10^{-7} Q_e F$$

where F is read directly from Fig. 2 and P_L is the cumulative probability of leakage failure up to that age. Age intervals may be considered by using the F differentials (Fig. 3).

The global estimate then simply assumes that the failure rate is average for the components size, shape, welding and age; and that it is typified by some group of components with known failure statistics. Other factors may of course make it better or worse.

MODIFYING ESTIMATES FOR SPECIFIC PLANT

The global estimate may be modified for specific plant. This is partly because of the influence of learning curves as discussed in Appendix 4; and because of the overall effects of differences in quality.

The first learning curve is for the technology as a whole, and it is a longer-term influence which has little bearing on immediate comparisons. For most purposes it may be disregarded or it may be assumed to be incorporated in the global estimate statistics. The other learning curve is for the age of the design of a plant. Very new designs have higher than average failure rates while old established designs are better

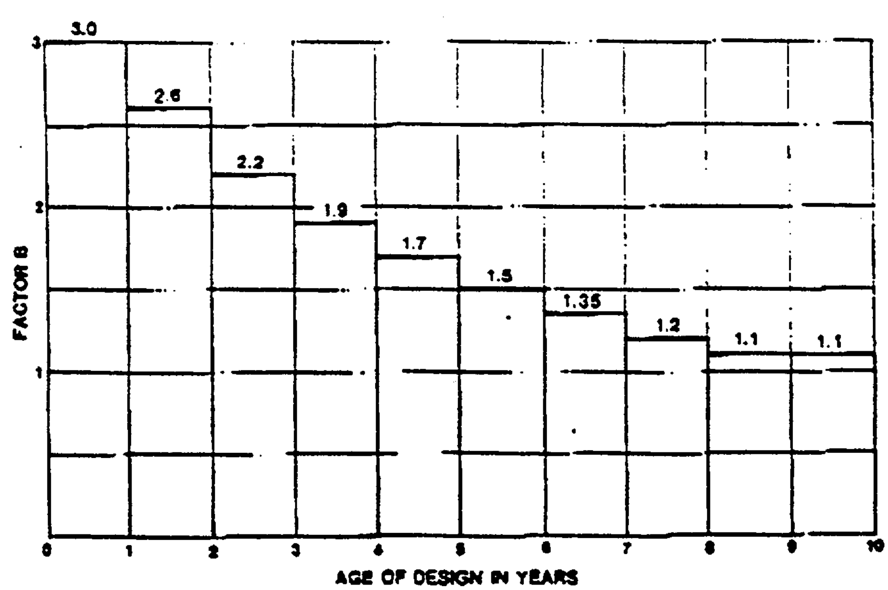

Fig. 4. Hypothetical design learning curve.

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than average. The age may be measured from start of service. Figure 4 is a hypothetical curve for B based on sparse data. It must be used with caution.

The influence of quality on failure probability is not yet numerically evaluated. Better design, better manufacture, better operation, and better in-service inspection must each yield some improvement over the average, but little data is available now.

WASH 1318[2] is an example of one evaluation of quality factors but it is subjective and not based on statistics. It estimated the factor of improvement for US nuclear plant over the average quality of commercial plant, to be about 10 to 100 on failure probability.

Only snippets of hard numerical data are available. Reference 3, for example, estimates the influence of all methods of defect detection in service to give an improvement factor of about three over the average for nuclear plant. While this improvement is not a reduction in the actual failure rate it does improve the safety of the plant.

One ploy would be to avoid the problem if possible. The EPRI[4] statistics now available would permit a direct comparison for some nuclear component made to the same quality.

FACTORING FOR FAILURE CAUSES

If the component being considered is subject to average conditions of stress and environment, etc., then there is no need to factor for any detailed cause of failure.

Table 3 typifies the mix of failure causes to be expected generally. It should be sufficient to consider this table and to modify it to suit the industry and components being evaluated. Some failure causes may be reduced in importance or deleted, and others added or increased in importance. Actual statistical experience would best justify such changes to the overall perspective given by the table.

Some components, however, are subject to unusual conditions of environment or fatigue stress levels, etc., and it may be important to evaluate the difference in risk due to some such particular cause of failure.

One must be careful, when doing this, to maintain an overall perspective of all other failure causes. Considering, for example, fatigue failure; some suitable model might show that the fatigue failure probability is say 10 × or 100 × higher than average. In that case it may be adequate to simply use the model to factor up. If on the other hand the model shows the fatigue failure probability to be lower than average, it would be fallacious to conclude, on the strength of that alone, that the overall failure probability is significantly less than average.

The following procedure is suggested to avoid this common pitfall:

(1) Establish the modified failure probability as determined in the previous sections.

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TABLE 3
MAIN CAUSES OF PIPE LEAKAGE AND THEIR RUPTURE PROBABILITY

Main cause of failure		1	2	3
		% Age of total leaks	P_c/P_L	P_c % of total leaks
Manufacture and fabrication	Wrong and defective base materials	9·6	0·08	1·74
	Welding	11·8		
Material selection		28·8	0·03	0·80
Fatigue	Vibration	4·3	0·20	0·88
	Low cycle	7·8	0·03	0·23
Expansion and flexibility		2·7	0·10	0·27
Corrosion Erosion		24·6	0·02	0·47
Maloperation		2·1	0·45	0·93
Thermal and mechanical shock		1·3	0·20	0·26
Miscellaneous		7·0	0·04	0·27
Total		100·0	—	*5·85

This table is a composite which typifies the statistical data to be found in refs. 4, 6, 7 and 8. It is not a comprehensive list of failure causes but it does model about 93% of all failures, and highlights the main causes of ruptures.
The table is intended for guidance and to provide an overall perspective on various failure causes. It should be modified to suit circumstances.
Column 1 is exactly representative of ref. 6 only and is fairly representative of refs. 7 and 8 also. The EPRI[4] statistics differ in that they have relatively fewer low-cycle fatigue failures.
* The P_c/P_L ratio in Column 3 is an estimate based on an appraisal of all the data in refs. 4, 6, 7 and 8. An additional component of P_c/P_L should be included. This may be determined by the fracture mechanics model in ref. 9.

(2) Establish the likely distribution of failure causes from actual failure statistics, i.e. generate a perspective table like Table 3.
(3) Apportion the modified failure probability according to this table.
(4) Factor each portion with a suitable model.
(5) Sum the factored portions to estimate the overall failure probability.

Many models are to be found in the literature, for particular failure causes such as fatigue. One by the author[1] could be used for the fatigue scaling in Step 4. Another by Arnold[5] also gives a similar scaling for fatigue failure.

Such detailed modelling can only be justified in dealing with problem points, e.g. if fatigue is a particular problem for a component then a probability model of fatigue failure is useful. It may help to evaluate and even reduce the problem. On the other hand if fatigue is not a particular problem there is little purpose in proving some very low level of failure probability for that one cause without also focusing attention on all the others.

ESTIMATING CATASTROPHIC RUPTURE

If the probability of leakage failure P_L is known, then a reasonable estimate may be made of the probability of rupture and catastrophic leakage P_C. As an overall statistic, about 5% to 10% of all leaks are ruptures.

Such a global estimate is, however, insensitive to some factors which are statistically quantifiable. Better estimates are possible if more of the data available are used. The most obvious refinement is to use the last two columns of Table 3. The procedure and approach may be just as for the previous section on the factoring for detailed causes. It can all be done as one exercise. The resulting estimate for P_C will be around 6% of the total P_L which may be slightly optimistic, especially for pressure vessels as opposed to small pipes.

This approach is in fact insensitive to the high rupture risk for highly stressed thick-walled vessels which may also have low fracture toughness. A further component of P_C/P_L should therefore be added. This may be determined from the fracture mechanics model given in ref. 9. Figures 5, 6 and 7 are reproduced here to

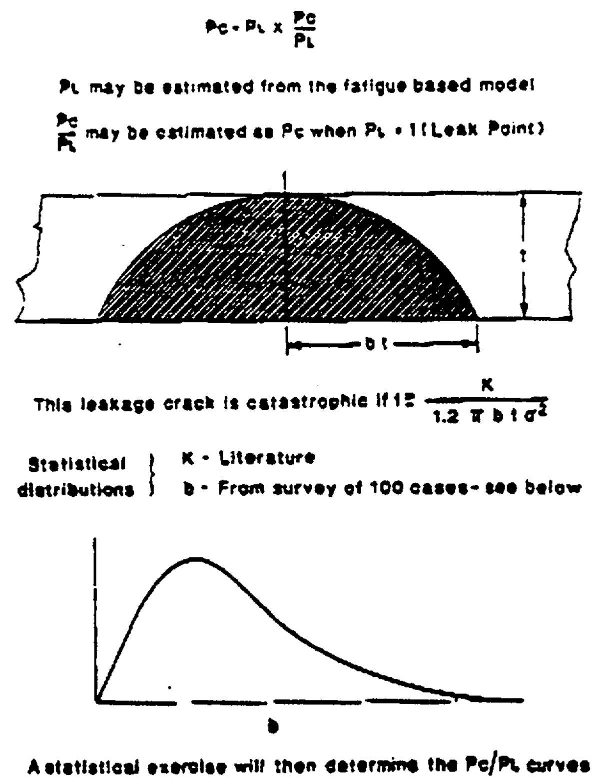

Fig. 5. The approximation strategy for catastrophic failure probability– P_C.

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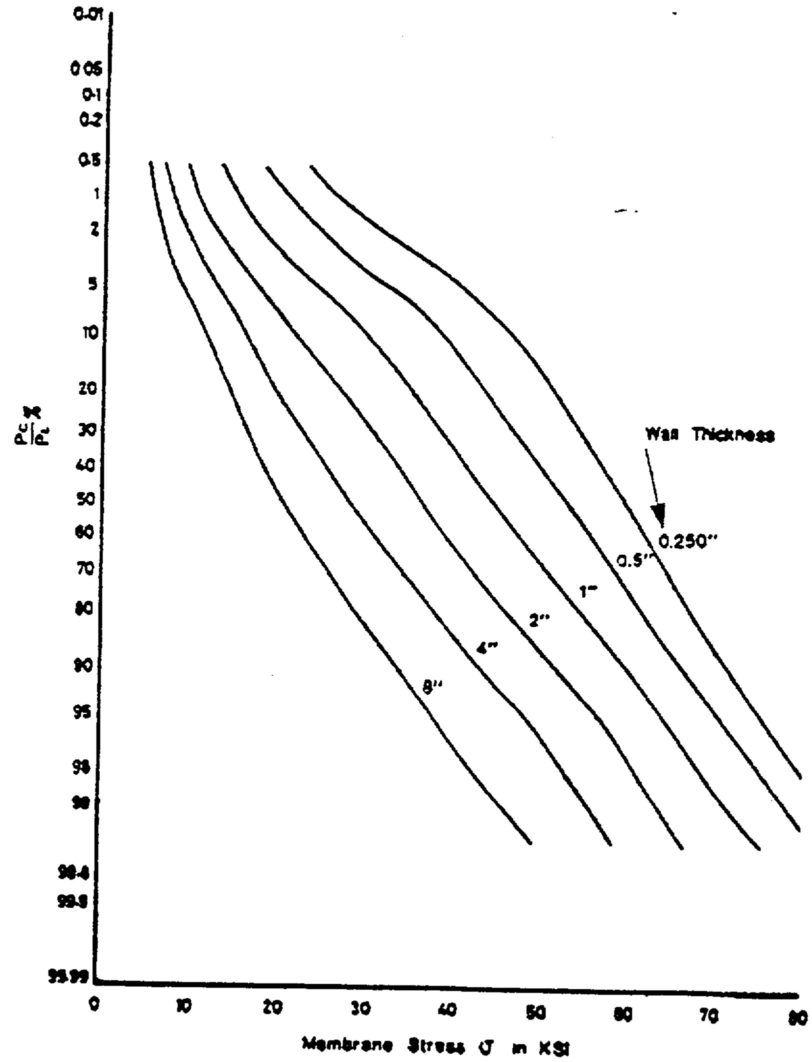

Fig. 6. P_C/P_L curves for vessels at an operating temperature of 500°F—RPV case. Input parameters: $\mu(k) = 220$ KSI$\sqrt{\text{in}}$; $\sigma(k) = 22$ KSI$\sqrt{\text{in}}$; $R/t = 15$; $\mu(\sigma_y) = 72$ KSI; $(\sigma_y) - 9$ KSI.

Fig.
F

(13)

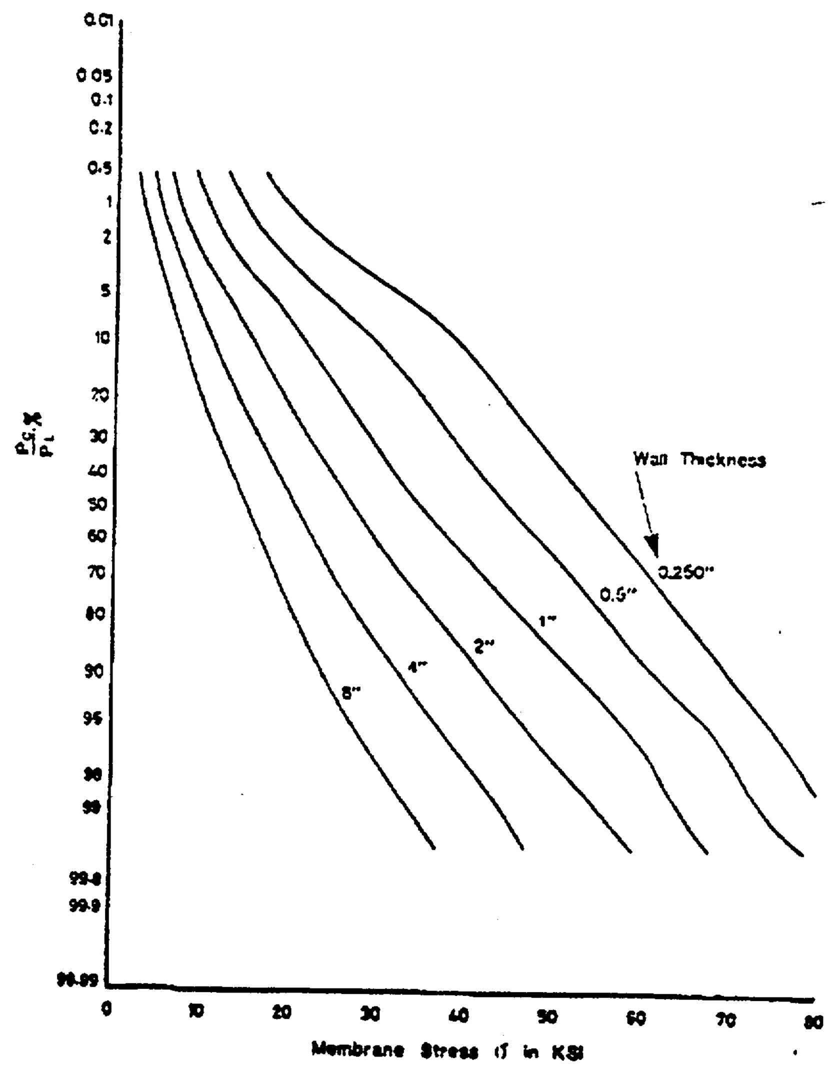

Fig. 7. P_C/P_L curves for vessels at the recommended hydrotest temperature—RPV case. Input parameters: $\mu(k) = 145\,\mathrm{KSI}\sqrt{\mathrm{in}}$; $\sigma(k) - 10{\cdot}5\,\mathrm{KSI}\sqrt{\mathrm{in}}$; $R/t = 15$; $\mu(\sigma_u) = 79\,\mathrm{KSI}$; $\sigma(\sigma_u) = 9\,\mathrm{KSI}$.

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illustrate the approach used. Alternatives to Figs. 6 and 7 are readily produced for different circumstances.

This model will make a trivial P_C/P_L contribution for most cases, but in many cases it will be the overriding factor. Used in addition to Table 3 it provides more sensitivity as well as perspective to the estimating procedure.

APPENDIX I

1. THE Q CONCEPT—QUANTIFICATION FOR SIZE AND SHAPE

1.1. The need to quantify the size and shape factor

Many factors help to determine the level of risk of failure for a component. The statistical evidence cited later in this appendix shows that one of the most significant factors is the size and shape of the component. It follows then that to quantify risks in a model it is necessary to evaluate the risk effects of different sizes and shapes.

1.2. A logic for quantification

Leakage failure usually means a wall breach at some relatively small zone in the material plenum. Usually such leaks will have grown from defects and imperfections in the material.

A logic for quantifying the 'size and shape' influence on failure probability may be developed from a consideration of the simplest form of pressure vessel, i.e. a typical length of pipe. Its size and shape is fully defined by the three dimensions of length L, diameter D and wall thickness t.

The influence of each of these on leakage failure probability may be considered separately as follows:

1.3. Length influence

It may be postulated that failure probability increases directly in proportion to length. For example, a 1000-in length of pipe bears a 10 times greater failure probability than a 100-in one, all else being equal. The fundamental premise behind this statement is an assumption that failure probability is an inherent property of the stressed material, and that it is simply proportional to the number of 'weak spots' and hence the length. Weak spots are bends, junctions, welds, flaws, etc.; assumed to be uniformly distributed.

1.4. Diameter influence

All else being equal in the material the influence of diameter is seen to be the same as length, i.e. it determines the total area from which a failure point may occur. The small influence of curvature is ignored, for this order of magnitude study.

The tube may be thought of as being developed from a simple plate of area πDL.

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1.5. Thickness factors

Unlike length and diameter, the thickness factor has a more complicated influence on the probability of a leakage breach. Considering fatigue failure for example, the following factors are each known to have a potential influence on the probability of a fatigue crack breaching a vessel wall:

(a) Probable maximum size of defect.
(b) Probable number of defects of various sizes.
(c) Probable crack growth rate(s).
(d) Probable crack proportions.

Each of these is in turn influenced by many other factors including the wall thickness. The cumulative effect of these factors determines the probability of a leakage failure in a vessel wall given a specified fatigue history; and P_L is clearly some function of t.

1.6. A general form of quantifier

It is not possible, with the data available, to theoretically determine precisely the overall influence of t.

From the foregoing, however, it may be concluded that the following expression gives the general relationship between failure probability and the 'size and shape' factors.

$$P \propto D^1 L^1 f(t)$$

The $f(t)$ term may be considered to be generally represented by one of the range of curves illustrated on Fig. 8. These depict families of feasible curve shapes for the function $f(t)$ plotted on log–log scales.

All the curves are shown as sloping generally from top left to bottom right. This is for consistency with knowledge about the actual values of x as determined later.

It is assumed that the log–log plot for $f(t)$ is a curve of gradually changing slope. The range of interest for t spans about two decades at the extremes and about one decade or less for the vast majority of vessels (say 0·2 in to 2·0 in).

It follows that the appropriate portion of whichever curve represents $f(t)$ may be represented by a straight line with little error, in order of magnitude terms. Any such straight line on a log–log scale is of the form $P \propto t^x$.

The influence of size and shape on failure probability may then be approximated by the following proportionality:

$$P_L \propto L^1 D^1 t^x \qquad \text{or} \qquad P_L \propto A t^x$$

A being the developed plate area. Such an index law may be used to provide an adequate representation over a range of values of t. While the indices of D and L are 1 the index for t is more complex. If the value of x can be established, then the term

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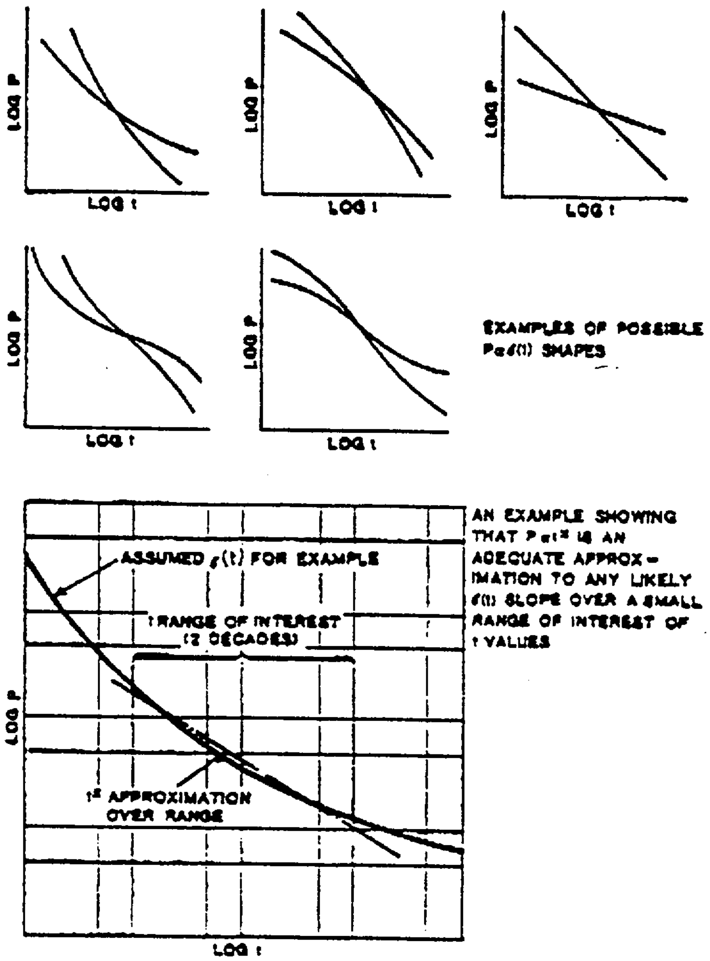


Fig. 8. Illustrating that t^x is an adequate approximation to $\phi(t)$.

DLt^x becomes the required quantifier. Several statistical evaluations of x are now possible and they are all about -2. These are given later.

It is interesting to note, however, that a range of discrete-integer x values corresponds to some of the more obvious intuitive hypotheses that have been made and used by various authors. These are listed in Table 4.

It must be emphasised that all these candidate quantifiers are of the same basic type as volume, length and area. They are simply measures of physical quantity. They do not purport to explain any particular failure mechanism such as fatigue or stress corrosion cracking.

However, the candidate to be chosen should ideally represent the global failure

TABLE 4
AN ILLUSTRATIVE LIST OF QUANTIFIER HYPOTHESES

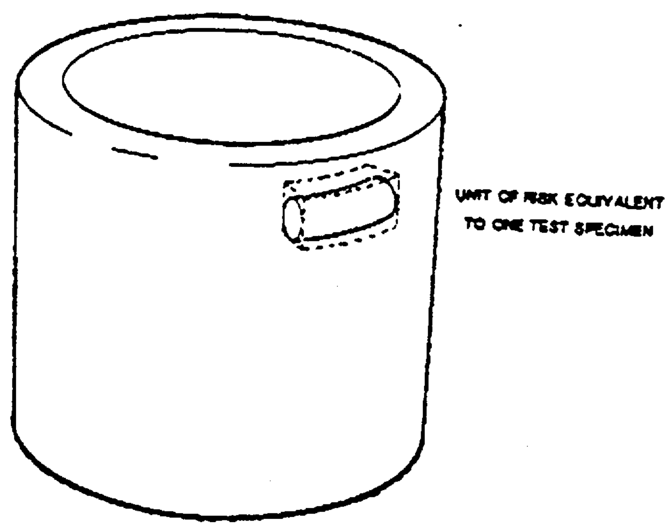
Hypotheses	*Dimensions of risk quantifier*		
That risk is proportional to material volume	$P \propto V$	or	$P \propto D^1L^1t^1$
That risk is proportional to surface area	$P \propto V/t$	or	$P \propto D^1L^1t^0$
That risk is proportional to some characteristic length, e.g. weld length, pipe length	$P \propto V/t^2$	or	$P \propto D^1L^1t^{-1}$
That risk depends on geometric proportionality, e.g. per vessel, per nozzle, Q value	$P \propto A^1t^{-2}$	or	$P \propto D^1L^1t^{-2}$
General form of hypotheses	$P \propto A^1t^n$	or	$P \propto D^1L^1t^n$

probability effect of size and shape. The number it generates may then be used in an exact weak link analogy, viz:

$$\text{Chain failure probability} \propto \text{number of links}$$

$$\text{Vessel failure probability} \propto Q \text{ number}$$

Generally, for pressure parts the 'maximum size of defects' and the 'number of



The 'Q' value for the vessel strake is the total number of geometric units i.e.

$$\frac{\text{TOTAL VOLUME OF WALL}}{\text{VOLUME OF A SPECIMEN OF WALL THICKNESS } t \text{ - LENGTH } 4t}$$

Fig. 9. The Q value of a vessel strake.

such defects' both depend on geometric proportionality. Thicker walls can and do have bigger defects but fewer of them. This is an inherent factor in the manufacture of all components, especially pressure vessel components. Geometric proportionality is therefore a logical choice.

Another factor which makes this an attractive choice of quantifier is the fact that it is a dimensionless number. There are basic scientific reasons why such numbers are robust correlators of test and field data.

The statistical data which follows also supports this choice of quantifier. Figure 9 illustrates a physical interpretation of geometric proportionality as a quantifier. The physical proportions of a typical tensile test specimen were taken as an arbitrary definition of unit risk. This choice was influenced by the availability of statistical data on the failure probability of such specimens. However, it must be emphasised that the arbitrary choice is not germane to the Q concept, neither is the data on specimens. Both are nevertheless useful for some purposes.

2. STATISTICAL EVIDENCE SUPPORTING THE Q CONCEPT

2.1. *The broad conclusion*

There are many sets of statistical data now available, each of which alone points to the merit of the Q concept of geometric quantification for the 'size and shape' factor of risk.

The first is an extensive set of data on weld defect density. Although this risk is one stage removed from actual failure, the index determined for x is still of the order of -2. These values of x may be determined from computerised statistical optimisations which are described later (see Appendix 2).

The next three sets are data on actual failures on BWR pipe welds, again showing indices in the region of -2 for x. Whilst almost all of these failures are from stress corrosion cracking (SCC) it should be noted that the Q concept forwarded in this paper is not aimed at any one failure mode, but is a general quantifier that spans all modes of failure.

Pipe failure statistics provide further evidence on the value of geometric quantification. Both the Rasmussen study[10] and the EPRI statistics reported by Basin and Burns[4] on pipe failures show that smaller pipes have a higher failure rate per unit of length than larger pipes.

The same may be observed for several different pipeline failure statistics. The Andersen study[11] at Bradford University shows the trend clearly for four different pipelines, with enough data to determine three values of x.

The statistical evidence from 'Licensee event reports' on piping systems as reported by Bush[12] also shows that geometric quantification gives better correlation than length. This applies to the pipe fittings as well as the pipes themselves.

These observations mean that when length $(D^1 L^1 t^{-1})$ is used as a quantifier then

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the results still require to be adjusted for an inverse thickness (t^{-1}) effect. The overall results indicate that DLt^{-2} is a better quantifier of the failure risk. The following are more detailed discussions of the various data sources.

2.2. *Weld defect statistical data related to the Q concept*

Reference 13 gives an analysis of defects in pressure vessel main seams. It reports on 599 vessel main seams of a variety of thicknesses giving a total of 2336 m of welds containing 806 defects.

This wealth of statistical data provides a means of testing the validity of the general quantifier hypothesis listed in Section 3.6. In particular, ref. 11 gives data on numbers of defects, wall thicknesses and total lengths of weld. It is possible then to establish which is the best quantifier of 'defect numbers', i.e. what is the most likely value of x for this purpose. This value will give some indication of the x value needed to quantify failure probability.

Table 5 is based on data extracted from Table 1 of ref. 13. It refers specifically to 'critical defects', i.e. the ones which have failure potential.

Given the general form of the hypothesis to be $P \propto At^x$, a computer optimisation exercise determined the value of x to be $-2{\cdot}46$. This means that the term $At^{-2 \cdot 46}$ is the most likely quantifier of the risk or expectation of having a critical defect in a weld. The statistical significance level of the result is 99%, i.e. there is only a 1% probability that the result was pure chance, without a causal relationship.

The result compares well with the Q concept of ref. 1 which implies that the term DLt^{-2} (or At^{-2}) measures the risk of actual leakage failure.

The two terms are of course not directly comparable because they measure

TABLE 5
AN ANALYSIS OF OBSERVED CRITICAL DEFECTS IN WELDS TO EVALUATE A RISK QUANTIFIER

Wall thickness t (*mm*)	*Area of weld observed* A (1·75 t × *length*) (*m*^{2})	*Number of observed critical defects*	*Predicted number of critical defects from law*
18	6·4	37	36·9
31	21·4	67	32·4
44	68·3	30	43·7
56	31·9	6	11·3
68	29·1	4	6·4
100	50·2	9	4·3

Given the hypothesis that $P_{cD} \propto At^x$, a computer exercise determined the optimum value of x to be $-2{\cdot}46$. This indicates the law $P_{cD} = 7042\,At^{-2 \cdot 46}$ for the observed welds.
This data is related to defects found during inspection and then removed. Whilst it is true that what is of interest is the defects that are not removed, the general trend of a decreasing defect density can be read directly across.

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different risks. The 'defect incidence' risk must be modified by size and distribution probabilities and crack growth rates, before it represents 'leakage failure'.

2.3. *BWR pipe failure statistics related to the Q concept*

Table VII of ref. 12 provides some statistical data on BWR pipe weld failure rates due to inter-granular stress corrosion cracking. Some of the data is reproduced in Table 6.

TABLE 6

AN ANALYSIS OF OBSERVED BWR PIPE WELD FAILURES TO EVALUATE A RISK QUANTIFIER FOR SIZE AND SHAPE

Physical data for pipe welds			*Failure statistics for pipe welds in 10^{-4}/weld*		
Nozzle nominal diameter (in)	*Estimated weld area (in²)*	*Estimated wall thickness (in)*	*Dresden 1 after 15·7 years*	*BWR mks. 1 and 2 after 8 years*	*BWR mks. 3 and 4 after 4 years*
2	1·47	0·133	—	30·5	—
4	5·88	0·267	845	50·5	251·6
6	13·20	0·400	1684	40·7	—
8	23·5	0·533	909	40·2	141
10	36·7	0·667	—	—	125
Optimum value of x assuming $P_w \propto At^x$			−1·79	−1·81	−2·78
Significance level			<90%	95%	97·5%

Reference 12 does not quote all the physical data for the welds. It simply refers to pipe nominal diameters. It was assumed for the purposes of this exercise that all the welds were designed for the same pressure; and that the wall thicknesses may be estimated as $D/15$. The weld areas are then $0{\cdot}367D^2$ based on a weld width of $1{\cdot}75t$.

Again, as in Section 4.2, it is then possible to establish what quantifier gives the best prediction for the named event; i.e. what value of x gives the optimal correlation with the observed failure rates.

Three separate exercises were carried out, one for each of the plant types quoted, with different service histories.

The results and confidence levels are also shown in Table 6. The optimal values of x are clearly of the right order to support the Q concept as a crude quantifier, which implies an x value of -2.

2.4. *Rasmussen study data*

Appendix III of the Rasmussen report[10] gives the results of a comprehensive study of all the then available pipe failure data. The quantification is based on length, so that $DLt^{-1} \propto P$ is implied; and the overall conclusion drawn was that smaller pipes ($\leq$4 in) were about 10 to 20 times more likely to fail than larger pipes ($\geq$4 in). It may be observed that the change in failure rate corresponds roughly to the change in size, viz. small pipes are typically 1–2 in and large pipes are typically 10–20 in, say.

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It follows that a quantification based on geometric proportionality (DLt^{-2}) would have produced one failure rate for all sizes. viz. ref. 1 defined the risk quantifier Q as $Q = DLt^{-2}$ so that the various Rasmussen report[10] failure rates all correspond roughly to $6{\cdot}4 \times 10^{-10}/Q$ year. This refers to the median 'LOCA Initiating Rupture Rates' per plant year in Table III 6.9 of the report.[10]

2.5. *EPRI pipe failure statistics*

EPRI NP-438[4] reports on a total of 237 PWR and BWR pipe system failures on 55 power plants up to August 1976, representing a total of 249 plant years of operation. This is clearly a significant sample of failure trends.

Table 7 is based on Table 3.4 of ref. 4. It gives the distribution of failures by pipe size.

TABLE 7

DISTRIBUTION OF US NUCLEAR PLANT FAILURES BY PIPE SIZE

	Size (in)				
	(≤ 1)	(> 1 ≤ 6)	(> 6 ≤ 10)	(> 10)	*Not specified*
Number of failures by category	77	66	14	9	37
Number of failures by half lengths	143		23		—

It is known[10] that a typical plant contains about 16 500 ft of pipe of less than 4 in diam. and about 18 500 ft of pipe of greater than 4 in diam., making a total of 35 000 ft.

Roughly speaking then, half the pipe length is in the two smallest size categories on Table 7 and the other half is in the largest two size categories. The failure rates per foot of length, however, differ by a factor of × 6·2 for the two halves.

This is again a clear indication that geometric proportionality rather than length is a more useful measure of failure risk. The per Q year failure rate for all sizes is roughly $6{\cdot}1 \times 10^{-8}$.

Only 9·3% of the failures were pipe ruptures, giving a rate of $5{\cdot}7 \times 10^{-9}$ per Q year.

Most of the plant are in the first few years of life when the failure rate is known to be higher than the mature plant failure rate.

A rupture rate of about 2×10^{-9} per Q year could then be applied to a mature plant based on this data. This compares well with the 6×10^{-10} figure estimated earlier from the Rasmussen report.[10]

It must be emphasised that the above rough Q values contain a mix of parent and weld metal, and that weldment metal is typically 50 times more likely to fail than parent material. The Q values were based on the outside diameters and assuming that all thicknesses were 1/12 of them.

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2.6. *Pipeline statistical data*

Andersen[11] gives failure rates by pipe size for five different pipelines. Four of these show the linear reduction with diameter of the failure rates/unit length. The fifth gives data at only one diameter range and hence cannot reveal any trend.

One of the pipelines gives only two diameter ranges, so that statistical exercises are not possible. Also they are ill-defined ranges in comparison with the other three.

Table 8 gives the results of statistical analyses of the data given for these three pipelines. As for the previous exercises, optimum values of x were determined in three separate exercises to determine the predictor At^x. Wall thicknesses and diameters are assumed to be linearly related within each class of pipeline.

The results again show x values in the region of -2, which indicates that the non-dimensional geometric quantifier is the most effective predictor of the influence of size and shape.

TABLE 8
'SIZE AND SHAPE' RISK QUANTIFIERS FROM PIPELINE STATISTICS

Data source	*Optimum value of x given* $P \propto At^x$	*Likelihood of causal relationship* (%)	*% Of variation explained by predictor* R^2 *test*
Oil pipelines (W. Europe)	$-2 \cdot 0346$	95	80·37
Transmission gas (USA)	$-1 \cdot 9123$	95	62·54
Interstate gas (USA)	$-1 \cdot 6078$	90	52·98

The arithmetic means of the diameter ranges were chosen to represent point data; together with Poisson means for the failure rate confidence limits quoted.

The third column in the table gives the probability that x is 'non-zero'; i.e. the likelihood that there is a causal relationship between the predictor and the observed results. It is not the confidence level at which x has been determined.

The last column is an R^2 test where

$$R^2 = 1 - \frac{\sum(\text{observed data} - \text{predicted data})^2}{(\text{observed data})^2}$$

It is the percentage of the observed variations which is explained by the predictor alone. These percentages are relatively high considering the unavoidable crudity of some of the assumptions made for the exercise.

2.7. *Licensee event report statistics*

Bush[12] in his Tables IX(a) and IX(b) gives 'distributions of reported licensee event reports in piping systems'. Table IX(a) is for 1970–75 and (b) is for 1976. The 'events' refer to failures and abnormalities on US nuclear plant pipes and their fittings. The statistics are broken down by pipe diameter.

Table 9 gives data extracted from these source tables, with all events from 1970 to 1976 summed. This table also shows the relative typical lengths of pipes per plant ≥ 4 in and <4 in.

The last column shows the relative event rates for the smaller category in relation to the larger. Again, the evidence clearly shows that geometric quantification (At^{-2})

TABLE 9
DISTRIBUTION OF REPORTED LICENSEE EVENT REPORTS IN PIPING SYSTEMS, BY PIPE SIZE

Pipe size	*Number of events reported*	*Typical pipe length per plant (ft)*	*Relative event rate* $\frac{\textit{small pipes}}{\textit{large pipes}}$
≤ 1	103		
$>1 \leq 2$	9	16500	5·03
$>2 \leq 4$	12		
$>4 \leq 6$	3		
$>6 \leq 8$	2		
$>8 \leq 10$	8	18500	1
$>10 \leq 20$	7		
>20	2		

as opposed to a 'per foot' (At^{-1}) quantification would have produced one fairly constant rate for all categories. 'Surface area' (At^0) would show a poorer correlation than length (At^{-1}). Volume (At^1) would show the poorest correlation of all.

These statistics and those from the EPRI report[4] clearly have a large common set. They should not be regarded as entirely additional evidence; but Sections 2.5 and 2.7 are mutually corroborative.

3. DISCUSSION OF THE EVIDENCE AND ARGUMENT

3.1. General application of the approximation

Section 2.3 showed that the 'size and shape' factor of risk is amenable to mathematical modelling, and that there may be good reasons for a general quantifier hypothesis of the form $P \propto At^x$. While this is most noticeably true for the pipe shape used to illustrate the approximation it must be stressed that it can also be true for any element of surface area with an associated wall thickness. The pipe-like shape is not germane to the argument. It is equally applicable to head shape and for nozzles or any tapering sections. For tapering sections the approximation becomes $P \propto \sum t^x \delta A$ but this cannot change the value of x unless the premises of the approximation are invalid, i.e. unless x is a significant function of t.

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Since the basic purpose of any pressure-containing part is to bound some plenum with areas of material of finite thickness(es) then this approximation ($P \propto \sum t^x \delta A$) will always apply. It is feasible then that one value of x will apply universally to all pressure containing parts given that they are fabricated in the same conventional manner and subject to similar loading conditions and failure modes.

Most, but not all the statistical evidence available for the determination of x, refers to pipes. Three items refer to nozzle welds and another includes pipe 'fittings'; but these indicate the same value of about -2 for x as is indicated by the many items of pipe statistics. Table 11 also supports the Q concept. This may infer that the Q value is more widely applicable than to just the piping analysed in this paper.

TABLE 10

SUMMARY OF STATISTICAL EVIDENCE ON THE Q CONCEPT

Data source	*Optimum x value*	*Significance of causal relationship* (%)	R^2 *fraction of variation explained for optimum x value* (%)	R^2 *assuming* $x = -2$ *i.e.* $P \propto At^{-2}$ (%)
Weld defects	−2·46	99	85	81·4
Dresden 1 nozzles	−1·79	90	73·5	71·86
BWR mks. 1 and 2	−1·81	95	97·4	96·4
BWR mks. 3 and 4	−2·78	97·5	99·88	91·88
Oil pipelines (W. Europe)	−2·03	95	80·37	79·84
Transmission gas (USA)	−1·91	95	62·54	59·4
Interstate gas (USA)	−1·61	90	52·98	27

3.2. *Summary of evidence on x values*

Tables 10 and 11 give a summary of the statistical evidence on the Q concept. They support the conclusion that the true value of x is in the region of -2.

The weight of statistical evidence now looks impressive, but several questions may be posed:

(a) What is the statistical significance of all the evidence in showing that there is some causal relationship between the quantifier At^x and observed data?
(b) Given that there is; then what value (or values) of x does the data indicate?
(c) Given this value of x, then how well does the quantifier fit or predict the observed results (i.e. ignoring all other factors of variability)?
(d) How does At^{-2} relate to the various global failure statistics available?
(e) Would a quantifier of the form $P \propto A(t \div c)^x$ give better correlations?
(f) How widely does the correlation apply?

These questions are discussed in the following sub-sections.

TABLE 11
ADDITIONAL SOURCES OF DATA SUPPORTING AN x VALUE OF -2

Rasmussen Reactor safety study[10]
EPRI pipe failure statistics[4]
Licensee event report statistics[19]

3.3. *Significance of causal relationship*

The individual items of statistics in Table 10 have significance values ranging from 90% to 99%. These show a low probability of a chance occurrence of the observed statistics without a causal relationship with the At^x quantifier.

The combined effect of Tables 10 and 11 is essentially multiplicative but could be complex to determine rigorously; i.e. giving the weighting to various qualities of data and sample sizes.

It is concluded then that there is a causal relationship between the proposed size and shape quantifier At^x and the observed statistics.

3.4. *A typical value for* x

The significance tests show that there is a strong correlation between the quantifier At^x and the statistics for failure. It may not be inferred, however, that the determined optimum values are known to be correct with the same high confidence level. The true value of x could be significantly different for each case.

The determination of the 95% confidence intervals for the value of x for each data population, shows that the value of -2 will be contained in each interval for all data sets.

It is concluded that the round number -2 adequately represents x for component failure. This suggests that the dimensionless Q number (DL/t^2) is an adequate quantifier for the effect of size and shape on failure probability.

3.5. *The prediction capability of* At^{-2} *in perspective*

The results of the individual exercises summarised in Table 10 show that the prediction capability of the quantifier At^{-2} is high given well-defined statistical populations. It may be seen that, given an appropriate constant of proportionality for each population (group or sub-group), its performance is good. The R^2 values in the last column give an indication of this. Table 12 and Fig. 10 give more direct comparisons.

This assessment of the performance of At^{-2} is inevitably a little pessimistic because of the nature of the data used. Even within these well-defined populations, other unknown factors of variability must have influenced the results significantly. Nevertheless, its prediction performance is clearly useful on its own given a defined population with known average failure rates.

However, populations and sub-groups are not always so well defined and

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TABLE 12
COMPARISON OF ACTUAL STATISTICS WITH PREDICTIONS

Data set	*Observed failure rates*	At^t *prediction*	At^{-2} *prediction*	*Prediction error factor for* At^{-2}
Dresden	845	1008·42	1145·01	1·36
	1684	1096·39	1145·23	1·47
	909	1167·95	1148·21	1·26
BWR mks. 1 and 2	30·5	34·38	40·67	1·33
	50·5	39·04	40·39	1·25
	40·7	42·11	40·39	1·01
	40·2	44·65	40·42	1·01
BWR mks. 3 and 4	251·6	249·55	172·34	1·46
	141	145·7	172·96	1·23
	125	122·21	172·49	1·38
Weld data	37	36·9	28·89	1·28
	67	32·4	32·58	2·06
	30	43·7	51·6	1·72
	6	11·3	14·88	2·48
	4	6·4	9·2	2·30
	9	4·3	7·34	1·23
Oil pipelines (W. Europe)	2·97	2·36	2·37	1·25
	1·56	1·28	1·32	1·18
	0·66	0·88	0·91	1·38
	0·39	0·67	0·697	1·78
	0·48	0·53	0·565	1·18
	0·39	0·45	0·474	1·22
	0·44	0·38	0·409	1·08
	0·55	0·33	0·359	1·53
Transmission gas (USA)	1·08	1·85	2·45	2·27
	1	1·16	1·47	1·47
	0·958	0·68	0·816	1·17
	0·75	0·49	0·565	1·33
	0·792	0·381	0·432	1·83
	0·583	0·314	0·35	1·67
	0·292	0·268	0·293	1·00
	0·125	0·234	0·253	2·02
	0·083	0·202	0·216	2·60
Interstate gas (USA)	0·41	0·62	1·21	2·95
	0·476	0·39	0·566	1·19
	0·351	0·286	0·34	1·03
	0·476	0·233	0·243	1·96
	0·248	0·2	0·189	1·31
	0·103	0·177	0·154	1·50
	0·105	0·158	0·129	1·18

identified in advance of actual failure experience. At^{-2} on its own can only account for part of the variations which may be observed in real-life failures.

The following estimates are cited to illustrate the point and to give a perspective on the role that can be played by At^{-2}, expressed in Q_e units.

The EPRI PWR power plant pipe failure statistics[4] recorded failure rates of $3 \times 10^{-5}/Q_e$ Yr. These Q_e numbers are based on the author's interpretation of the

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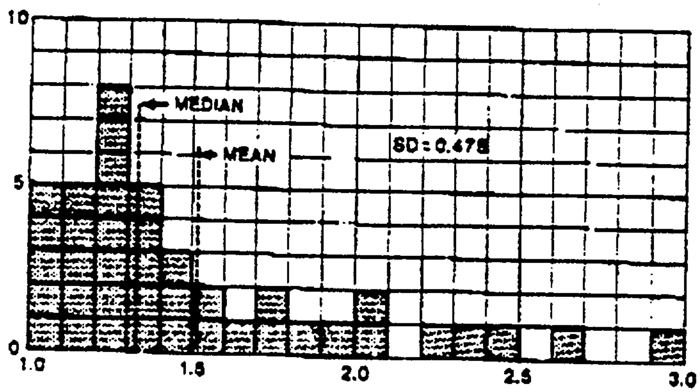

Fig. 10. Error factor distribution.

pipe and nozzle weld failure statistics actually quoted in the various data sources cited.

If the Dresden BWR nozzle welds are considered separately as a subset they can be seen to have failure rates of about $4{\cdot}8 \times 10^{-6}/Q_e$ Yr, i.e. $\times 160$ greater than the average, based on Q_e numbers. This difference may be attributed to the influence of the stress corrosion cracking problems that were blamed for the failures.

Had the quantification been based on material volume (At) instead of $Q_e(At^{-2})$, with no weld penalty of $\times 50$, then apparent differences could be much greater. For example, a difference factor of $\times 3{\cdot}4 \times 10^6$ would be obtained by comparing 1 in^3 of 4-in BWR nozzle weld with 1 in^3 of 30-in diam. parent pipe material. The former has a failure rate of 4×10^{-3}/Yr and the latter $\sim 1{\cdot}2 \times 10^{-9}$/Yr.

The following is a break down of the $\times 3{\cdot}4 \times 10^6$ factor into the three causative factors:

Due to weld metal penalty	$\times 50$
Due to size and shape (At^{-2})	$\times 422$
Due to SCC problems	$\times 160$

Even greater differences of about $\times 10^7$ to $\times 10^8$ are seen by comparing SG tube failure rates with pressure vessel failure rates, on a material volume basis. It will be seen below that they exhibit roughly the same failure rate when quantified in terms of failures/Q_e Yr.

3.6. At^{-2} *related to overall statistics*

It is interesting to compare widely different statistics using geometric size and shape quantification. Table 13 and Fig. 11 compare the overall average non-disruptive failure statistics for vessels pipes and tubes mainly to ASME designs. When the statistics are reduced to failures/Q_e Yr they are surprisingly consistent, being about $2 \times 10^{-8}/Q_e$ Yr. This means that a realistic quality target for nuclear

TABLE 13

FAILURE RATES/Q_e Yr FOR SOME OVERALL STATISTICS

Item	*Source reference*	*Non-disruptive failure rate/Yr*	*Estimated average* Q_e	*Failure rate/*Q_e *Yr*	*Fig. 11 key*
All vessels as summarised in WASH 1318[2]—per vessel	2	2.0×10^{-3} 2.5×10^{-4}	3.3×10^{4}	6×10^{-8} 8×10^{-9}	a
ASME I and ASME VIII vessels—per vessel	2	10^{-3}–10^{-4}	3.3×10^{4}	3×10^{-8} 3×10^{-9}	b
EPRI pipe failure statistics ≤6 in—per plant	4	0·82	3×10^{7}	$\sim 2.7 \times 10^{-8}$	c
EPRI pipe failure statistics >6 in—per plant	4	0·13	6×10^{6}	$\sim 2.2 \times 10^{-8}$	d
All SG tube failures averaged per plant	14	53	8×10^{8}	6.6×10^{-8}	e
As above excluding the six plants with epidemic failures	14	14	8×10^{8}	1.7×10^{-8}	f

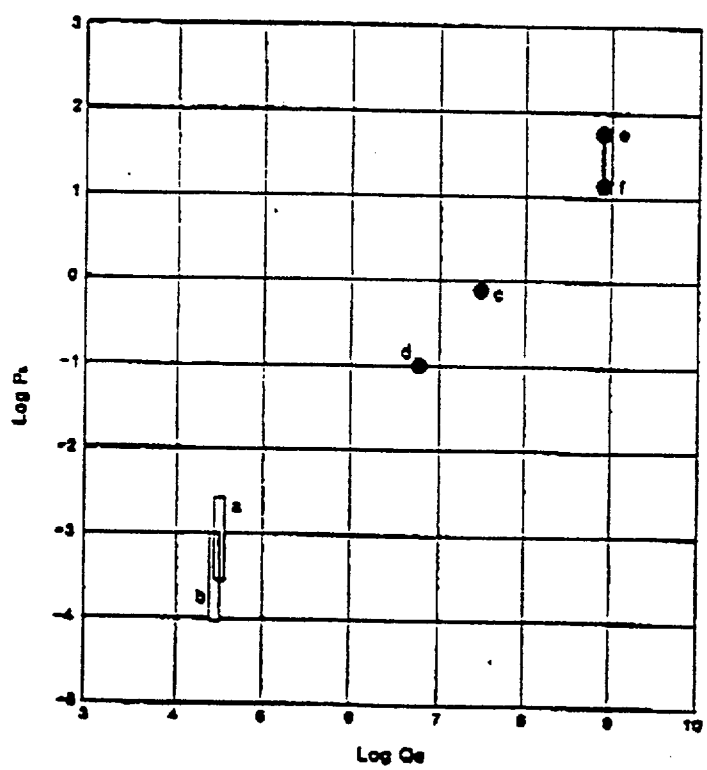

Fig. 11. Failure rates/year versus Q_e for some overall statistics. Key on Table 13.

plant might be in the region of $10^{-10}/Q_e$ Yr. This target is needed to give an RPV ($Q_e \sim 10^4$) a failure rate of 10^{-6}/Yr.

So far, however, the evidence shows that such a target is not being achieved on the US power plant.

3.7. Is there a more sensitive quantifier?

In theory the $P \propto At^x$ approximation could be replaced by more sophisticated versions which might yield better correlations with the observed data.

Several alternatives were tried, with computer optimisations, but no significant improvements were made.

Only one is worthy of mention, this is the approximation $P \propto A(t+c)^x$, which would apply if some threshold effect applied to the wall thickness. When applied to the various data sets the improvement in correlation was marginal and the optimised x values varied widely. This defeats the objective, which is to establish one universal correlator which may be used for prediction purposes.

3.8. How widely does the correlation apply?

It may be concluded at this stage in the development of the model that its use should be restricted at present to pipework failure probability estimates.

A reason that may be advanced for this caveat is that the data base for pressure vessel failure is much less than that for pipework failure. It may be that there are other factors and further statistical data which can be used in due course and after further work, to justify or refine the model for use in pressure vessel failure probability estimation.

APPENDIX 2

THE STATISTICAL OPTIMISATIONS FOR x, DIMENSIONLESS GROUPS AND SCIENTIFIC METHODOLOGY

The text of this report refers to several statistical optimisations for the x values in the quantifier At^x. Such optimisations are fairly common mathematical techniques and are used extensively in statistical work. The optimisation may be performed manually but is most accurately and cheaply done by computer.

The purpose of this appendix is to illustrate the technique to those readers who are not familiar with it. This appendix also argues the case for using dimensionless groups, and the scientific methodology.

To illustrate the optimisation for x the statistics on the 'number of critical defects in welds' may be treated, for example ref. 13.

Very simply a range of experimental x values are tried and for each a correlation check may be made on Fig. 12. Perfect correlation would be a line at 45° passing

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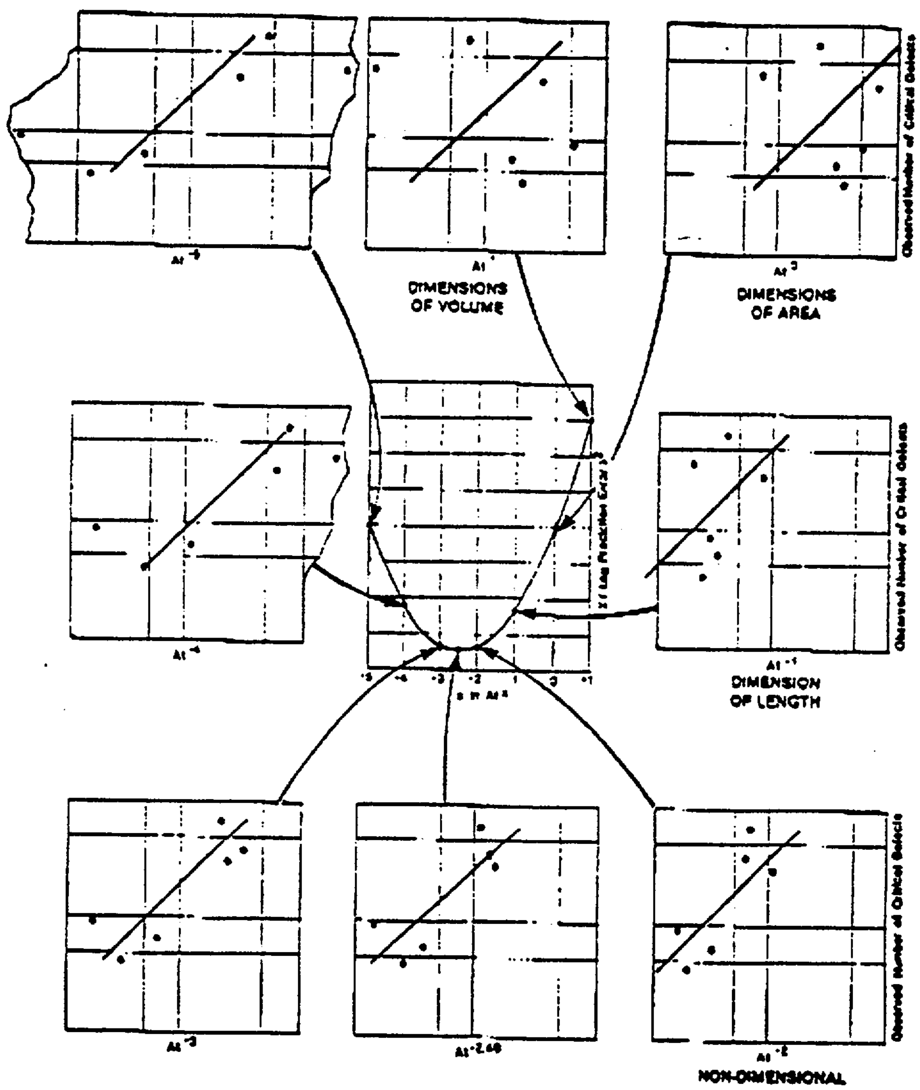

Fig. 12. Illustrating the optimisation for n.

through every data point. The assumptions implicit in the successive plots are as follows:

Number of defects $\propto At^1$ (volume)
Number of defects $\propto At^0$ (area)
Number of defects $\propto At^{-1}$ (length)
Number of defects $\propto At^{-2}$ (geometric)
Number of defects $\propto At^{-2\cdot46}$ (optimum correlation)
Number of defects $\propto At^{-3}$ (beyond optimum)
Number of defects $\propto At^{-4}$ (beyond optimum)
Number of defects $\propto At^{-5}$ (beyond optimum)

Statistical spread due to many factors makes perfect correlation impossible for the one factor being considered, i.e. the size and shape factor At^x. It is, however, possible to see which value of x gives the best correlation. It may then be argued that this optimum is statistically the most likely true value of x.

The optimum x value of $-2{\cdot}46$ for this set of statistics was actually determined by computer. It may be observed that adjacent graphs for At^{-2} and At^{-3} also show correlations which appear almost as good.

Figure 12 also shows in the centre a plot of $\sum$ (log of x-axis error)^2 for the various quantifier hypotheses listed above. This confirms that the optimum and its two adjacent points ($x = -2$) and ($x = -3$) are all almost equally good as correlators.

The significance of this is that the optimisation curve is flat near the optimum and that little is lost by rounding off to the most convenient whole number, which is -2. The actual optimum values for most of the other cases cited in the report were in fact closer to -2. These also all referred to actual failure statistics, not defects.

It should be noted that all the quantifier hypotheses considered are meant to be simple measures of size and shape. They are in no way intended to explain the fundamental causes for failure. However, it is now an observed fact that the most successful correlator is the dimensionless number At^{-2}.

This is to be expected, because it completely excludes the influence of the physical dimensions that inevitably help to determine failure probability. All the other quantifiers listed involve the dimension of length to some $\pm$ index. It may be observed from the plot on Fig. 15 that increasing this index modulus (regardless of $\pm$ sign) increases the correlation error drastically and on a logarithmic scale.

This means that the dimensionless Q number DL/t^2, could be used to measure the influence of size and shape. The influence of other factors such as fatigue, stress, rupture risk, corrosion and quality, etc., may then be modelled for separately in the system proposed by the author.

The need for a dimensionless group to quantify one effect is statistically illustrated above: but it may be regarded as a prerequisite for success in modelling any effect. In the system proposed by the author all the groups suggested are in fact dimensionless,

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and their product is dimensionless; so is probability, viz:

P	Probability ratio to unity
Q	DL/t^2 dimensionless quantifier
S^5	(Strain ratio)^5—dimensionless
N	Number (of strain cycles), i.e. many defined events/one event
T	Dimensionless stress distribution number
P_C/P_L	Ratio of two numbers
P_w/P_p	Ratio of probabilities
B	Learning curve ratio
F	Age factor ratio

APPENDIX 3

THE WELD METAL PENALTY

Weld metal and heat-affected-zone material are more likely to fail than parent metal. An evaluation of several different sets of statistical data, summarised in Table 14 shows that a penalty of about $\times 50$ should be applied to weld zones when estimating the global risk, i.e. $P_w/P_p = 50$.

TABLE 14
A SUMMARY OF THE VARIOUS P_w/P_p ESTIMATES

Item number	*Source*	P_w/P_p *estimate*
1	Vessel fatigue tests	34
2	Pipe failure statistics	30–100
3	UKAEA data	31–43
4	Socket weld tests	8
5	Defect incidence	38
6	Nuclear plant abnormal operations	45–90
7	US PWR and BWR statistics	43
8	Best estimate	50

This number is associated with a definition of the weld zone as being $1{\cdot}75t$ wide, which is quite typical for most welds. Any other definition would require an appropriate scaling of the $\times 50$ penalty.

An illustrative example of one typical P_w/P_p evaluation is the one based on the EPRI statistics[4] for 237 pipe system failures in light water reactors. In its summary of conclusions it states that 54 % of all the failures occurred in the welds, including the heat-affected zones, while 40 % occurred in parent pipe material. Since a factor of roughly $\times 32$ has been estimated for the volume proportions (parent metal/weld zones), then it follows that P_w/P_p is 43·2.

APPENDIX 4—THE INFLUENCE OF AGE

1. TIME RELATED FAILURE DATA FOR PRESSURE VESSEL COMPONENTS

References 4, 6, 7, 8, 14, 15 and 16 provide data which relate failure numbers to age. Each sample was taken in turn and a plot was made of cumulative failures against age. The general trend is always the same. While there is an obvious increase in the cumulative failure with age, there is always a reduction in the failure rate with age. This appears to apply for the first 20 to 30 years of life for pressure vessels.

The samples are for varied components with different average failure rates. In many cases that average is not known because while failure numbers and ages are known the total population to which they refer is not known. Nevertheless, it is possible to infer the influence of age on the failure rates.

The following ploy was used to separate this one factor. For each sample the cumulative failures in the first ten years was taken as unity and the curves were all replotted as fractions of unity against age. This gives a dimensionless measure of the influence of age and the effects as observed in the different samples may then be directly compared. The results are shown in Fig. 13A–K.

The choice of 10 years as the reference period was a compromise influenced by the following conflicting requirements:

(a) The longest time possible is the ideal.
(b) Extrapolation of data for shorter-term samples must be kept to a minimum.
(c) Simplicity requires a round whole number as a standard for reference.
(d) The reference period must be at least a significant fraction of the design life of typical plant.

The general similarity of trends in Fig. 13A–K is quite unmistakable. There are, however, differences in the shapes of the curves. Some of the reasons for these differences are different age effect factors and biasses discussed later.

In spite of the noticeable differences, an arithmetic mean of all these curves, as shown in Fig. 2, is close enough to them all to represent the general effect. The error factors are not significant compared with other sources of error in predicting failure probability.

The simplest approach to probability prediction would be to take this curve to be representative of all the age factors in combination. The total effect of F and B could be read from Fig. 2, say.

This approach, however, is insensitive to some of the information available, particularly about the influence of new designs; and some optimistic errors could result. The following section gives an appraisal of age related effects which may help to interpret the statistics available.

Before proceeding, however, it is worth noting that the samples are extremely varied in nature. One is for heavy vessels, some for pipes and some mixed. Another is

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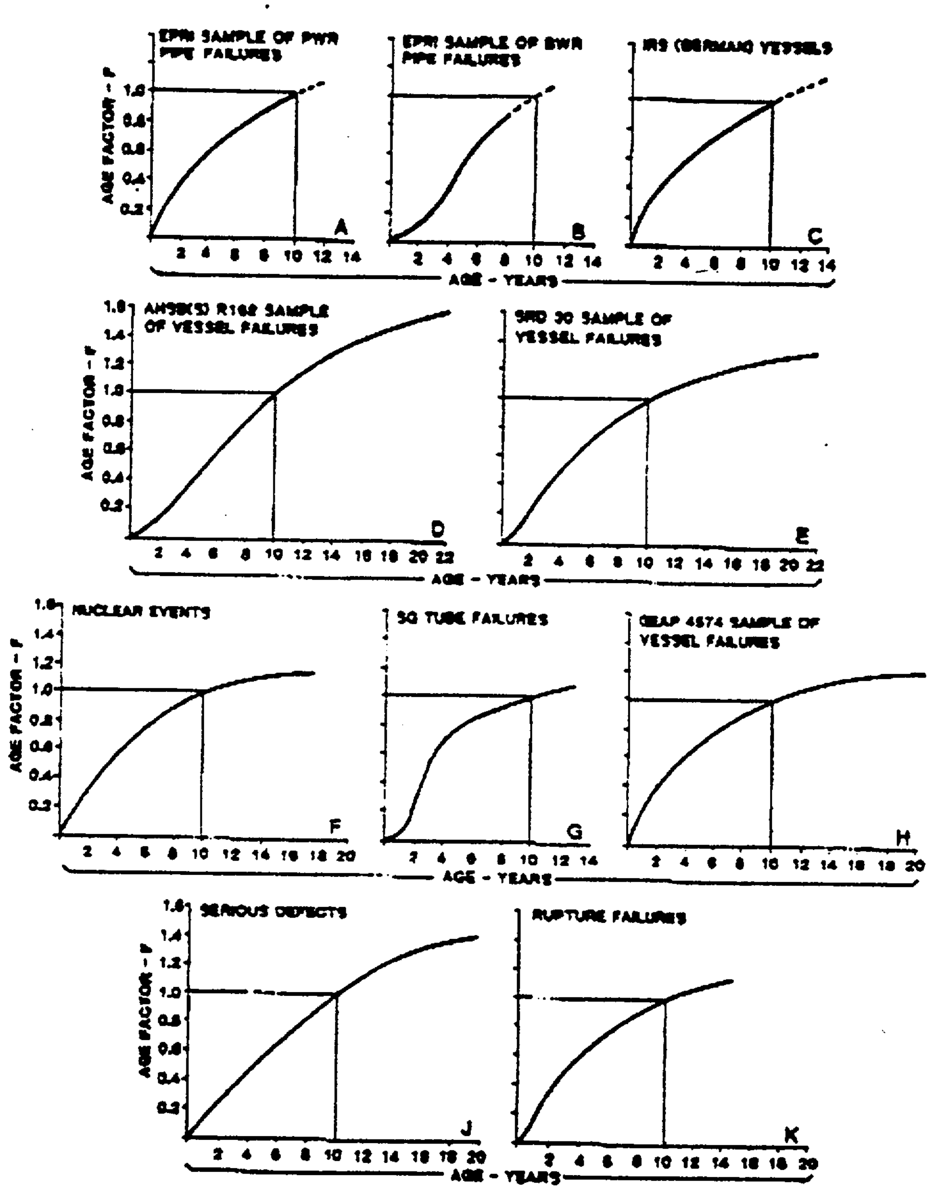

Fig. 13. Age factors.

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just for nuclear incidents. The definitions of failure for the various samples must have been different because some included minor defects and others did not.

In spite of this the age effects observed are generally similar and have a similar time constant.

Two of the samples, the serious defects and the ruptures, are a composite extracted from the others to test the hypothesis that the same age effect curve could be used. They appear to support the hypothesis, so that the approximation strategy of Fig. 1 is justified in this respect, i.e. it may not be argued that the average age effect is unrepresentative of either P_L (serious defects) or P_C (ruptures).

2. THE HIERARCHY OF TIME-RELATED CHANGES IN FAILURE PROBABILITY

The interpretation of the observed data requires an understanding of the nature of the various components of change which take place with time. Some of the data sets are likely to contain more than one component. The following is meant to clarify the relationships between known effects.

Time-related changes in component failure probabilities may be categorised at three different levels. These bear a hierarchical relationship to one another as illustrated in Fig. 14.

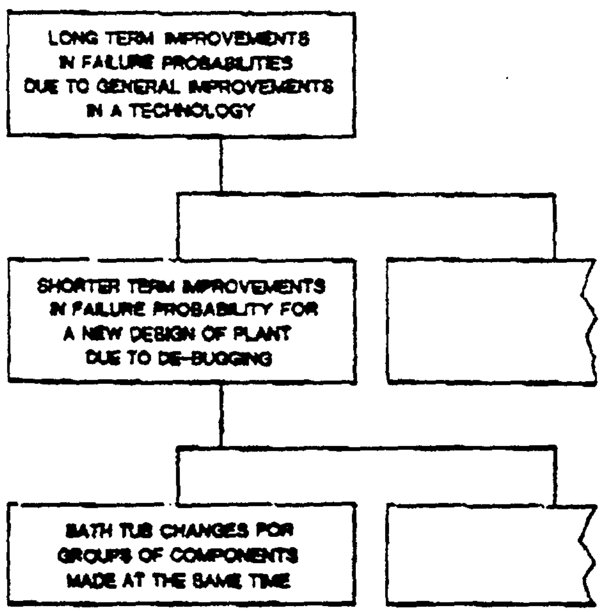

Fig. 14. A hierarchical categorisation of time-related changes in failure probability.

The most obvious and familiar changes are the observed bathtub distributions which are described in more detail later.

The failure statistics for a population of identical components all manufactured at the same time will produce such a bathtub distribution. This may be regarded as the lowest level of change in the hierarchy.

The next level is that due to the learning curve for a new design of component or plant. New designs inevitably produce an increase in failure probability over and above the average for equivalent established designs. The problems are eliminated in time but with decreasing rapidity. The overall result is a typical learning curve. Reference 17 illustrates these effects as they are observed on aero engines.

Reference 3 illustrates a learning curve for one particular PWR plant. It is, however, not strictly comparable with ref. 17 because it refers only to novel failures not the totals. Figure 4 is a hypothetical learning curve based on this sparse data.

One might speculate that the successive bathtubs for groups of components would change as illustrated in Fig. 15. The 'early in life' problems will be solved first, and the front end of the generic new design bathtub is depressed gradually with development of the design. The overall effect would be a learning curve such as Fig. 4.

The last level of change is that due to the long-term improvements that permeate the whole of a technology. Although each new design may start off poorer than average in failure rate, lessons are continually learnt and the average is gradually improving. The Rasmussen[19] report cites two examples. One is the improvement in road death statistics over decades, and the other is for aviation accidents.

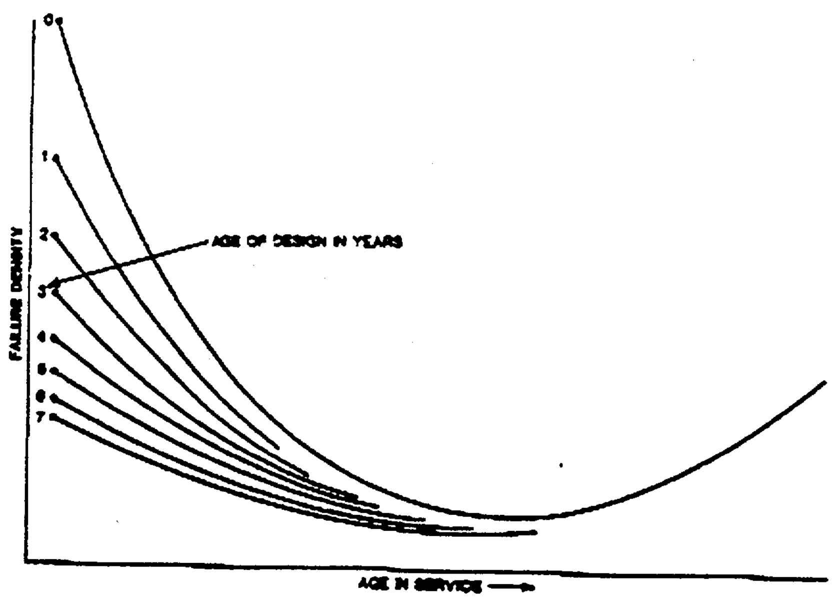

Fig. 15. Learning curve bathtubs.

This hierarchical categorisation identifies the basic elements of time-related changes: but it is inevitably an over-simplification and an idealisation. Many factors fog the overall pattern.

Nevertheless, the categorisation helps to understand the broad trends or components of change which permeate any set of data on time-related failure probabilities.

The bathtub front (Fig. 3) is the differential of the average curve shown in Fig. 2. It is obvious that the main component of change represented by these curves is the bathtub one: but the potential influence of the other levels of change needs to be probed before Fig. 2 may be taken to represent factor F.

3. INTERPRETATION OF THE PRESSURE VESSEL DATA

The ideal samples to determine the F factor alone would be large groups of components all made at the same time and to a well-established design, say 10 to 15 years old, so that the learning curve is over. To be of precise current interest it must be today's design and the failure rate must then be observed for about 20 to 30 years, during which time all technological progress must be suspended.

These ridiculously impossible but scientific requirements show that perfect data

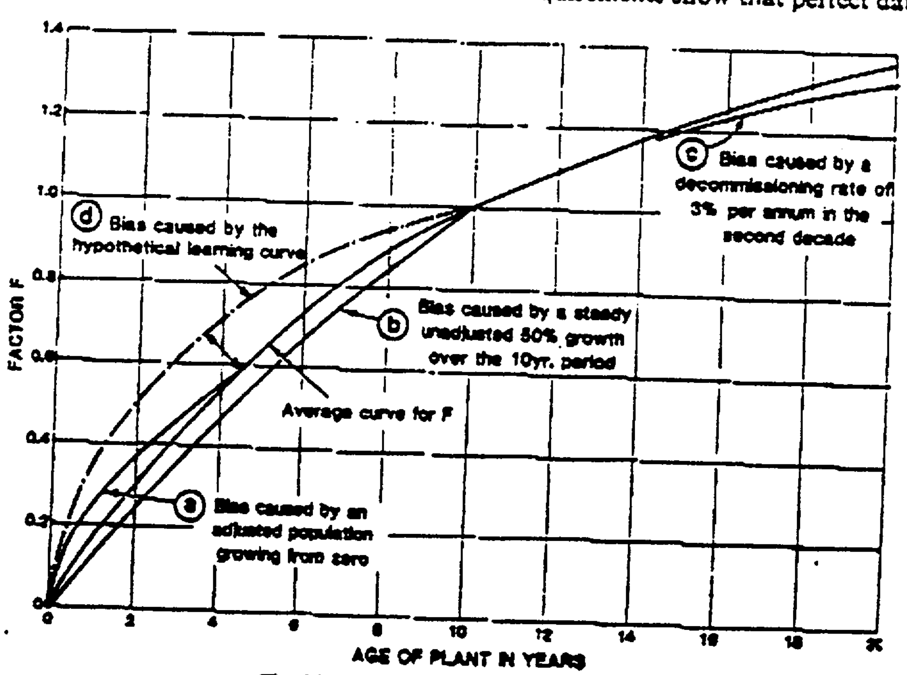

Fig. 16. Factor F sensitivity analysis.

will never be available and that the best possible use must then be made of the data which are available. The vital question is 'how truly representative is Fig. 2 of factor F?'. To what extent is the curve distorted by design learning curves and by general improvements in the technology as a whole? What are the effects of biasses which naturally occur due to growing and diminishing populations?

Sensitivity studies were made to appraise the most important of these factors. The general approach used was to assume that Figs. 2 and 3 are at least reasonably representative of factor F and to determine the likely bias effect of various other factors by integrating numerically over a 10-year period.

The results are shown in Fig. 16. Few of the statistics contain the Type (a) bias so that the averaged 10-year result is not seriously changed. The same may be said of the Types (b) and (d) biasses. Also, Types (a), (b) and (d) tend to cancel one another out.

Type (c) bias, on the other hand, is likely to be present in any longer term statistics so that the top end of the true curve for F should be slightly elevated. The error is not significant, however, for a period of say 20 years.

4. THE PARADOX OF A FAILURE RATE REDUCING WITH AGE

There are many fatigue-based theoretical models in the literature on vessel failure probability which are apparently in conflict with the factual statistical data in Fig. 13A–K. Also, at first sight it seems paradoxical that the failure probability density should diminish with age. This section is an appraisal of the problem, but unavoidably it amounts to an adverse criticism of some of these theoretical models. Some very extravagant claims have been made on the strength of such models, so that a more factual appraisal is necessary. Reference 3 by the author gives a brief appraisal of one aspect of this problem.

The theoretical models vary in detail but they usually use the following broad approach. They assume that fatigue is the failure mode which dominates and that fatigue crack growth is then a dominant factor in relating failure probability to age. They then assume that the accelerating growth of an individual crack reflects the failure probability of the assumed host vessel. These three assumptions are structurally important, but they are all demonstrably false.

In many sets of real-life statistics fatigue failure accounts for a minor fraction of the total. Furthermore, considering that minor fraction alone, it may be shown that the probability of the failure event is dominated by the probability of having a defect at all and its probable size. Crack growth rates have a trivial influence on most fatigue failure probabilities. It only matters for high-cycle fatigue failures, requiring over 10^5 cycles.

In reality there are several modes of failure to consider, and each mode has several regimes in which some factor or other may dominate the probability of failure.

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Fatigue is just one mode and crack growth dominates in one regime. It has a relevance to some small fraction of all real-life failures, perhaps less than 1%.

These models are in themselves useful in that they study the probable progress of one defect, and that may be very important, especially if it is a real defect in a vessel. There is no logical reason, however, to assume that the progress of that one defect in any way reflects the general probability of failure of any other vessel or group of vessels. Indeed the statistical evidence available shows clearly that during the working lives of most vessels such a model of failure probability cannot apply.

Generally speaking, for all manufactured components, real-life failure causes may be categorised under three headings as follows, regardless of particular modes of degradation.

(a) Failure due to initial defects of manufacture or design. These culminate early in life and diminish with age. They may be thought of as infant mortality or de-bugging. They are congenital defect failures and they produce more deaths early in life than later. Figure 17 curve (a) shows the diminution with age of the annual failure rate.

(b) Failures may also be caused by wear factors like corrosion, fatigue and erosion. These are usually accelerating with age and are represented by curve (b).

(c) Another category of failure cause is external factors which randomly damage a component; such as errors and accidents. They are not dependent on age and may be represented by curve (c).

The overall failure probability is the sum of these three categories; which is the inevitable bathtub curve. This applies generally to all things; but the time scales for curves (a) and (b) may vary enormously and the absolute levels of (a), (b) and (c) may also be very different. The variations are so great that the design life of a particular type of component may appear to be dominated by any one of the four curves, or parts of them.

It so happens that for most pressure vessels curve (a) seems to dominate. This means that most failures are caused by congenital defects of design and/or manufacture, not by the wear factors. This should be no surprise, because pressure vessels are deliberately intended not to wear out in their working design lives and usually have a considerable margin for safety. At the same time it is well known that design and manufacture may not always achieve that intent in spite of our best efforts.

Logically then Fig. 13A–K is the expected result of curve (a) and should not be considered a paradox. The theoretical fatigue models on the other hand represent curve (b). They are not so much wrong; they are just irrelevant and insignificant in the range of interest. They are incomplete and lack an overall perspective.

It may be concluded that mathematical models of the curve (b) type are useful for certain studies. They are not, however, valid as failure probability models for

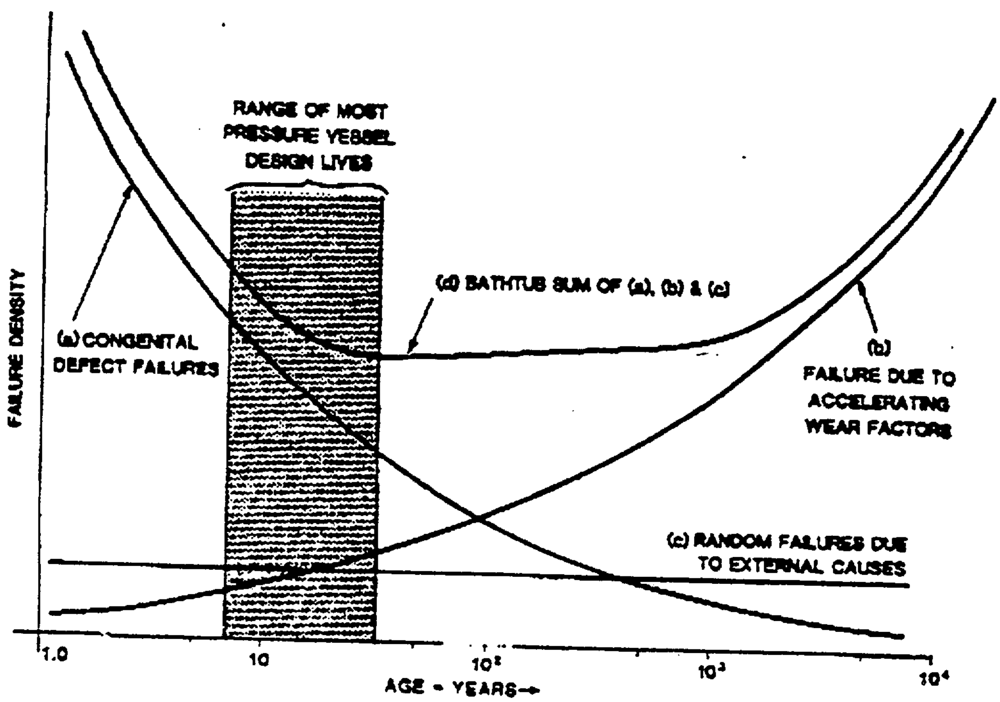

Fig. 17. The bathtub curve related to pressure vessels.

pressure vessels in their working life span. The observed bathtub front is more appropriate.

5. CONCLUSIONS AND RECOMMENDATIONS ON AGE FACTORS

1. Failure rates for pressure vessels generally improve with age. Several samples of real-life failure data show this clearly.
2. Three broad categories of time-related improvements in failure rates may be identified. These are long-term changes in a technology, shorter term design learning curves and typical bathtub curves. These bear a hierarchical relationship to one another.
3. The front end of the bathtub curves for pressure vessels spans 20 to 30 years at least.
4. The principal component of change to be found is the bathtub one. The other components have a lesser influence on the observed statistics for failure with age.

5. Statistics for very varied populations may be compared for age effect by reducing them to a non-dimensional ratio based on the total failure number in the first 10 years.
6. In their non-dimensional form all the different age effect curves have a striking similarity. An arithmetic average curve is numerically very close to each individual curve, and may be taken to be generally representative.
7. The factor F may be taken as this average for all the samples available in spite of the disturbing influences of the other factors and biasses to be expected in general statistics. Sensitivity analyses show these other influences to be marginal in effect. Factor F is therefore determined with a reasonable accuracy.
8. Factor B, on other hand, may only be roughly estimated from the data available. A hypothetical curve is offered for consideration, but it should only be used with caution.
9. It may be shown that the general curve for F applies also to serious defects and to ruptures, so that the approximation strategy suggested in Fig. 1 is valid in that respect.
10. Unless one is estimating for a new plant design there is no need to consider factor B. It may be assumed to be 1. New designs may be penalised by a curve such as the one shown in Fig. 4.
11. Many theoretical models in the literature are in conflict with observed facts in the relationship between age and failure probability. They are all based on fatigue and crack growth. They all assume that the progress of an individual crack somehow represents the overall failure probability of a vessel. This assumption is not justified by any theory or fact.

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PRE-DECISIONAL INFORMATION - OFFICIAL USE ONLY

RISK IMPACT OF ENVIRONMENTAL QUALIFICATION REQUIREMENTS FOR ELECTRICAL EQUIPMENT AT OPERATING NUCLEAR POWER PLANTS

Nicholas T. Saltos
Probabilistic Safety Assessment Branch
Office of Nuclear Reactor Regulation

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ABSTRACT

Historically, plants licensed at different times were subject to different guidance and requirements for electrical equipment environmental qualification (EQ). Newer plants follow NUREG-0588 Category I requirements (the EQ rule acceptable standard). A group of older plants follows NUREG-0588, Category II requirements, while the oldest plants follow DOR Guidelines. The latter two groups involve relaxation in EQ requirements such as qualification by testing, application of margins and consideration of aging and synergistic effects. These differences in EQ requirements, in conjunction with experience data and preliminary test results of cables (e.g., Okonite), indicate the existence of uncertainties associated with qualification methodologies and the reliability of equipment that must function in accident induced harsh environments. These uncertainties may be risk significant.

The objective of this preliminary risk analysis is to use probabilistic risk assessment (PRA) techniques to quantify the risk impact of electrical equipment qualified under the "old" EQ requirements (i.e., DOR guidelines or NUREG-0588 Category II requirements). However, limitations in current PRA models and data precluded an accurate quantitative risk assessment. Instead, a screening evaluation of the potential risk impact of electrical equipment that were qualified according to "old" EQ requirements was performed. This was achieved by parametrically reducing the reliabilities of equipment that are supported by electrical power and are required to operate in accident-induced harsh environments. These equipment include electrical components (cables, connectors, and solenoids) that must function in accident-induced harsh environments and which could be major contributors to core damage.

The scope of this preliminary analysis was limited to core damage prevention (considering internal events only) and to in-containment electrical equipment, with emphasis on cables. This was primarily due to time limitations and to the assumption that in-containment electrical equipment components are the most likely to be exposed to harsh environments. Although not included in this preliminary analysis, harsh environment reduced reliabilities of components which support accident mitigation equipment (e.g., containment fans and sprays), could be important to overall plant risk. In this evaluation, the emphasis is on cables since they are not routinely replaced, and they receive minimal maintenance.

The first step was to identify potentially important accident sequences, for both PWR and BWR plants, involving harsh environments in the containment. This was followed by the identification of equipment operations that must be performed during each of these sequences (e.g., 2 of 2 PORVs must open for feed and bleed). Next, generic insights from PRAs and related studies were utilized to select several accident sequences for more detailed evaluation and eventual inclusion in a parametric (sensitivity) risk study. The results of this scoping study were used, in conjunction with qualitative assessments of aging of in-containment electrical components to assess the potential risk impact of "old" EQ requirements.

Three plants were selected for quantitative risk analysis. These include two PWRs (Sequoyah and Surry) and one BWR (Peach Bottom). Resulting plant core damage frequency increases were found to be between 1×10^{-5} and 7×10^{-5} per reactor year for Sequoyah, between 8×10^{-5} and 5×10^{-4} per reactor year for Surry, and between 1×10^{-5} and 1×10^{-4} per reactor year for Peach Bottom. Such increases are of comparable magnitude to the core damage frequencies for these plants reported in the NUREG-1150 PRAs. More details are presented in Tables 1, 2 and 3 in chapter 3.

Major conclusions of this preliminary risk analysis are: 1) the risk impact of "old" EQ requirements could be significant if electrical component reliabilities are reduced in the presence of a harsh environment; 2) the magnitude of core damage frequency impact is plant specific; and 3) due to lack of reliability data bases and limitations in current PRA models, an accurate assessment of the risk associated with harsh environments is not possible at this time. Recommendations for future and more accurate evaluation of this issue are also included.

1.0 INTRODUCTION

1.1 Background

Nuclear power plant electrical equipment used to perform a safety function must be capable of operating reliably under all service conditions, i.e., normal operation as well as accidents postulated to occur during the equipment's installed life. This must be demonstrated by "environmental qualification" (EQ) of the equipment. Since safety systems rely on redundant equipment, EQ aims at demonstrating that a common-cause failure will not occur during design basis events. Specific requirements pertaining to EQ of certain electrical equipment important to safety are contained in 10CFR50.49.

EQ has evolved gradually over the years in terms of design criteria, technical sophistication, and licensing requirements. Plants of various vintages are committed to differing NRC EQ requirements [1]. The EQ rule implies that meeting the provisions of NUREG-0588 Category I (IEEE 323-1974 and Regulatory Guide 1.89, Revision 1) constitutes compliance with the rule. It requires that all new and replacement equipment in existing plants be qualified to its requirements unless there are sound reasons to the contrary. However, it does not mandate that any equipment previously requiring qualification to lower standards (i.e., NUREG-0588 Category II or DOR Guidelines) be requalified to the rule. This is termed as the rule's "grandfathering" provision. Grandfathering maintained important differences in EQ requirements for different groups of plants. Newer plants follow NUREG-0588 Category I requirements (the EQ rule acceptable standard). A second group of older plants follows NUREG-0588 Category II requirements, while a third group (the oldest) follows DOR Guidelines. The latter two groups involve relaxation in EQ requirements such as qualification by testing, application of margins and consideration of aging and synergistic effects as well as a reduction in the qualified limits for certain equipment.

There are approximately 84 operating reactors with "old" EQ requirements (i.e., NUREG-0588 Category II and DOR Guidelines). These differences in EQ requirements, in conjunction with preliminary test results of cables (e.g., Okonite and other pre-aged cable testing at Sandia National Laboratories), indicate the existence of uncertainties associated with qualification methodologies and the reliability of equipment that must function in harsh environments. These uncertainties may be risk significant, in particular for plants qualified under the DOR guidelines or NUREG-0588 Category II requirements. Therefore, quantification of the risk impact of electrical equipment qualified using "old" EQ requirements (i.e., DOR guidelines or NUREG-0588 Category II requirements) is needed. This would provide an overall risk perspective of issues related to "old" EQ requirements.

1.2 Scope and Objectives

A complete analysis of the risk impact of the environmental qualification (EQ) of electrical equipment should consider equipment in all locations, both in-containment and outside containment, where a harsh environment can occur during certain accidents. For each of these locations, the effect of the harsh environment on the reliabilities of electrical components, which support equipment that serve either a core damage prevention or an accident mitigation function, should be assessed.

The scope of the present analysis was limited to core damage prevention (considering internal events only) and to in-containment electrical equipment, with emphasis on cables. This was primarily due to time limitations and to the assumption that in-containment electrical equipment components are the most likely to be exposed to harsh environments (e.g., during LOCAs and in-containment main steam line breaks). It should be noted, however, that reduced reliabilities of some electrical equipment located outside the containment, due to the presence of a harsh environment (e.g., high energy pipe breaks and interfacing system LOCAs), could also have significant risk impact at some plants. Moreover, reduced reliabilities of electrical components which support equipment used for accident mitigation (e.g., containment fans and sprays), during the presence of a harsh environment, could be important to overall plant risk. The emphasis was on cables because they are not routinely replaced and receive only minimal maintenance. It is recommended that the scope of the present analysis be extended in the future to include electrical components outside the containment as well as those supporting equipment performing an accident mitigation function.

The major objectives of this preliminary risk analysis are listed below.

- Identify electrical equipment components, such as cables, connectors, and solenoids, that must function in accident-induced harsh environments and which could be major contributors to core damage.

- Use probabilistic risk assessment (PRA) techniques to conduct a screening evaluation of the potential risk impact of electrical equipment that were qualified according to "old" (i.e., DOR or NUREG-0588 Category II) EQ requirements.

It is recommended that the present analysis be extended in the future to include the following objectives.

- Obtain a more accurate assessment of the risk associated with EQ issues and use it to compare the risk impacts of the several EQ requirement standards (i.e., NUREG-0588 Category I, Category II and DOR guidelines).

- Identify areas where additional analyses and/or testing may be necessary to reduce EQ-related uncertainties.

- Use PRA techniques to identify and demonstrate the effecti.eness of measures for reducing risk (e.g., use of reliability assurance and maintenance rule requirements).

1.3 Limitations

As operating plants become older, their safety-related electrical equipment and components should maintain their ability to perform reliably in a harsh environment. Studies have shown that aging-related degradations, of both active components (e.g., valves and pumps) and passive components (e.g., cables), could cause significant risk increases if aging is not effectively managed. Ideally, PRA provides a method to assess the importance of harsh environment equipment reliabilities on risk. Models were developed to quantify the risk due to an increase in active standby component unavailability, passive component failure probability, and accident initiating event frequency. ~~This increase is estimated as a function~~ of equipment age, equipment aging rate and the quality and effectiveness of the plant maintenance program. In reality, there are limitations in current PRA models and data that preclude an accurate quantitative assessment of the risk significance of issues associated with the environmental qualification of safety-related equipment. The most important of these limitations are summarized below.

- *Lack of reliability data bases for equipment in harsh environments.* PRAs assume the same reliabilities in harsh environments as for normal operation. This implies that environmental qualification assures that equipment reliabilities stay at their normal operation levels when exposed to harsh environments during accidents. This PRA assumption, however, has not been validated by experimental evidence. In fact, in some cases, there is evidence to the contrary.

- *Lack of models to evaluate the impact of EQ requirements on equipment reliability.* In particular, there are no models to evaluate the impact of the lower qualification standards associated with "old" EQ requirements on electrical equipment reliability in harsh environments.

- *Lack of aging-related degradation data.* There are no adequate data for aging-related degradation of electrical components in their normal operation environments. This is particularly true for passive components, such as cables.

- *Lack of correlations between aging-related degradation of equipment and their ability to perform under accident-induced harsh environments.* This includes modeling the potential for common-cause failure of redundant equipment or components, in a harsh environment, following their aging-related degradation.

- *Lack of the detailed system descriptions required to assess the risk significance of EQ issues.* For example, current PRA models do not contain the level of detail that is necessary to investigate the operability of the steam generator level transmitters or the operability of a motor-operated valve control cable.

- *Lack of plant status instrumentation models.* Instrumentation indications are used by the operator during an accident to diagnose the status of the plant, make informed emergency response decisions, and develop appropriate accident mitigation strategies. For example, containment pressure indications will automatically actuate chemical sprays. However, in the event that automatic initiation fails, the operator can manually initiate spray operation if other indications are available. Current PRAs lack models that relate risk, via the operator interface, to containment pressure indication.

- *Insufficient PRA analyses for pipe breaks outside of containment.*

- *Limited models of post core melt accident management strategies.*

Due to the above mentioned limitations, a parametric (scoping) risk analysis was performed. The reliabilities of equipment that are supported by electrical power and are required to operate in a harsh environment, were reduced parametrically to simulate the effect of potential common-cause failures.

1.4 Methodology and Approach

The first step was to identify potentially important accident sequences, for both PWR and BWR plants, involving harsh environments in the containment. This was followed by the identification of equipment operations that must be performed during each of these sequences (e.g., 2 of 2 PORVs must open for feed and bleed). Next, generic insights from PRAs and related studies were utilized to select several accident sequences for more detailed evaluation and eventual inclusion in a parametric (sensitivity) risk study. The judgement for this selection was based on a combination of the following considerations.

- The presence of in-containment electrical components (e.g., cables, instrumentation and solenoid operators) which support safety equipment operations needed to prevent or mitigate accidents.

- Accident sequences during which these safety equipment operations take place, including timing and potential for recovery.

- The presence of electrical components for which there are reasons to believe that their reliability may be reduced during operation in harsh environments.

Finally, the selected accident sequences were used to perform a scoping risk study by parametrically reducing equipment reliabilities to simulate the effect of potential common-cause failures in a harsh environment. The results of this scoping study were used, in conjunction with qualitative assessments of aging of in-containment electrical components and the limited experience information available, to assess the potential risk impact of "old" EQ requirements.

2.0 INSIGHTS FROM LITERATURE REVIEW

A literature review was conducted to identify information that could be used to assess the risk impact of EQ requirements for electrical equipment at operating nuclear power plants. An early conclusion was that none of the published PRAs have explicitly considered aging and that no adequate data and models were available to perform a detailed quantitative risk assessment in the short term. For this reason, it was decided to perform a preliminary risk scoping study to assess the potential risk impact of "old" EQ requirements. Equipment reliabilities were reduced parametrically to simulate the effect of potential common-cause failures in a harsh environment. Only if this preliminary risk analysis indicates that the risk impact of "old" EQ requirements is potentially high, will a more detailed analysis be necessary.

The literature review provided several insights that guided this preliminary risk scoping study and could form the framework for a more detailed risk analysis in the future. These insights were used to achieve the following:

- focus the analysis on electrical equipment components supporting risk important operations which take place in accident-induced harsh environments (Section 2.1)

- develop a qualitative data base including information related to failures of electrical equipment components in harsh environments such as failure modes, failure mechanisms, NRC information notices and industry research test results (Section 2.2)

- identify EQ issues, i.e., "deficiencies" associated with the lower standards of the "old" EQ requirements such as not considering aging and synergistic effects (Section 2.3)

- identify risk-important electrical equipment components which may have, as a result of the lower standards of the "old" EQ requirements, reduced reliabilities when exposed to a harsh environment (Section 2.4)

2.1 Electrical equipment components supporting risk important operations in harsh environments

In-containment electrical equipment components whose failure (random or common-cause) can affect risk important operations were identified [2]. They are summarized below.

PWRs

- Cable systems (e.g., cable, connectors, penetrations, splices)

- PORV solenoid operators

- PORV block valve motor operators
- Instrumentation (pressurizer pressure and level, SG level detectors, containment pressure, primary RTDs, hydrogen detectors, and high-range radiation monitors)
- Electrical components providing support to containment isolation valves, containment fans and spray system (accident mitigation only)

BWRs

- Cable systems (e.g., cable, connectors, penetrations, splices)
- Safety relief valve (SRV) and Main Steam Isolation Valve (MSIV) solenoid operators
- MSIV bypass valve motor operators
- Low pressure and vessel level sensors, and reference leg detector piping
- High range radiation monitor (provides information to the operator for accident management, e.g., offsite evacuation)

Failure of these components can affect safety system operation, as well as operator actions, in one or more of the following ways:

- Failure to provide motive and control power to components inside containment (e.g., to start and run pumps and fans and open or close motor-operated and solenoid-operated valves).
- Failure to generate and convey electrical signals from in-containment instrumentation for automatic actuation and operation of ESF systems as well as for control room displays (e.g., SG level, BWR vessel water level, and containment pressure).
- Likelihood that a failure of an in-containment electrical component (e.g., cable) is spread to components outside containment (e.g., due to failure of protective devices, miscoordination among circuit breakers of different sizes, and erroneous signal).

An important factor that affects the reliability of the above-mentioned electrical components in a harsh environment is the time of exposure to such an environment. Equipment operations that are required to take place at the beginning of an accident that causes a harsh environment have better chances of success than equipment operations required several hours into the accident.

2.2 Qualitative failure data base of electrical equipment components in harsh environments

Stressors

Service conditions include normal (environmental and operational) as well as harsh environment conditions. Certain elements or "stressors" of service conditions can affect equipment condition and performance. Harsh environment stressors, in general more severe than normal (environmental and/or operational) stressors, may cause immediate failures in age-degraded components because of the high intensity or unusual nature of the stressor. This could defeat system redundancy by incapacitating the two or more paths or trains available for providing essential safety functions (common-cause failures). EQ programs aim to prevent such common-cause failures resulting from harsh environmental stressors contributing to aging of electrical components. Examples of normal environmental stressors are temperature, radiation, moisture, dust and distortion pressure. Examples of normal operational stressors contributing to aging of electrical components are thermal cycling, maintenance disturbances (e.g., flexing of cables) and current or voltage surges. Examples of harsh environment stressors, which can lead to common-cause failures of electrical components aged by normal stressors, are steam condensation, high temperature levels and gradients, radiation and chemical sprays.

Degradation Sites

Normal aging of electrical components could lead to degradations of concern and jeopardize the required safety performance under either normal or harsh environmental conditions. The latter condition is more critical because of the potential for high-risk common-cause failures. In order to assess the degree of degradation of the various in-containment electrical components, it is necessary to focus on locations where aging stressors are most severe. If components in those locations are free of degradation, then similar components in less stressed locations are likely to be in good condition.

Considerations that help identify potentially serious degradations sites are: a) maximum environmental severity during normal plant operation; b) physically demanding installation configuration; c) potentially susceptible designs; and d) records of experience. Examples of degradation sites are: 1) electrical penetrations to devices; 2) maximum thermal/radiation areas; and 3) wet or moist locations. The review of aging-related failures during normal operation indicates the presence of events in the following categories: corrosion, dirt, defective connector, loose connector, short/grounded, open circuit, cable insulation breakdown, and cable embrittlement. These event categories can be associated with one or more type of degradation sites.

Aging Mechanisms

Aging mechanisms describe how stressors affect particular material properties or components of electrical equipment in ways that may lead to several aging-induced failure modes when exposed to a harsh environment. Examples of aging mechanisms for cable systems are listed below [3].

- Temperature/Radiation/Oxygen-diffusion induced chemical reactions occur over time in polymeric compounds used as cable insulation and jacket materials. These reactions inject or leave electrolytes, charged ions, or other molecular debris in the molecular structure of these compounds. The effect of this is to increase the dc leakage currents (lower the insulation resistance), increase the ac losses and reduce the elasticity (increase brittle fracture) of the compound. When these cumulative changes in electrical and mechanical properties are followed by a rise in temperature, radiation dose rate and humidity, as during the presence of a harsh environment, the result is an immediate and substantial increase in leakage currents and ac losses and susceptibility to moisture induced shorts and grounds.

- Moisture entering cables as a result of breaks in (or diffusion through) the jackets initiates corrosion of shields. Moisture within cables and seepage through broken seals of connections may lead to the corrosion of connector contacts. This occurs over long periods of time leading to random failures during normal service. However, in a harsh environment, this failure mechanism is accelerated. Sudden intrusion of water into corrosion-sensitive components can cause the loss of shield continuity and raise the noise level. The functional failure of the affected circuit depends on its sensitivity to noise. Such failures, when combined with connection failures caused by accident-related flexing or vibration, would become common-cause failures.

- Cable flexing or vibration can compromise the silicone rubber seals used in cables with mineral-insulated connectors at cable terminals. This results in a decrease of the insulation resistance (increases leakage) and functional degradation.

Potential Failure Modes

Normal operation stressors affect electrical equipment performance by initiating aging mechanisms which may lead to degradation and eventual random or common-cause failure if this equipment is subsequently exposed to harsh environment stressors such as those of a LOCA. Equipment in locations where stressors are the most severe (degradation sites) is the most vulnerable. The various modes a particular equipment can fail (i.e., its "failure modes") are coupled with the stressors, failure mechanisms and degradation sites that are associated with that particular equipment. Examples of potential failure modes for cable systems are listed below [3].

1. Increased series resistance (an open circuit being the extreme case)

2. Increased leakage current (decrease of insulation resistance)

3. Grounding of a conductor

4. Short circuit between conductors

5. Large changes in ac losses or capacitance (impedance change)

6. Spurious signals from electrolyte or thermoelectric effects

7. Increased noise pick up (shielding or grounding problems)

In general, metallic conductor and connector components of cable systems possess characteristics that relate to the occurrence of failure modes 1 and 6; characteristics of insulating components relate to modes 2 through 5; and the properties of cable jacket and shielding components relate to modes 5 and 7. It is important to note that the sensitivity of operating electrical circuits to changes and noise in the cable system vary widely depending on the connected devices and the required accuracy of these devices. For this reason, the assessment of the cable performance in harsh environments must be based upon realistic circuit tolerance figures.

NRC Initiatives and Test Program

Through 1991, NRC has issued 172 information notices, 41 bulletins, and 15 generic letters related to EQ of various electrical equipment components. Several of these NRC actions involved in-containment components whose failure affects risk important operations (see Section 2.1 above). In addition, NRC has sponsored several research tests related to electrical equipment performance in harsh environments. Relevant information for risk-important electrical components is summarized below [2].

Motor Operators: EQ-related deficiencies of Limitorque valve operators (approximately 95% of motor operators used by the nuclear industry) were found. Deficiencies included the use of underrated terminal blocks, the use of terminal blocks that lack proper EQ, improper switch settings, unqualified internal wiring, problems with the similarity analyses, improper materials selection and assembly, and installation practices different from the tested configuration.

Solenoid Operators: Many solenoid operators are continuously energized during normal operation in order to fail safely in the event of loss of power. This creates higher internal temperatures, and can lead to faster aging, than those experienced by non-continuously energized solenoid operators. Operating problems with solenoid operators are mentioned due to causes such as high temperature ambient conditions, presence of hydrocarbon contaminants, and chloride contaminants causing open circuits in coils. NRC research testing of solenoid operators in harsh environments revealed considerable intrusion of water into the coil housing and a sensitivity to the use of air as a process medium.

Cables: In 1977 Sandia National Laboratories examined 55 cable qualification summary reports performed by Franklin Research Institute for its customers, typically cable manufacturers. This examination indicated that during harsh accident environments cables may fail with probabilities much higher than those assumed in the PRA. Recent Sandia LOCA testing of pre-aged cables showed that 18% of cables pre-aged to 20 years and subsequently exposed to a simulated LOCA environment failed. The percentage of failure increased to 23% for cables pre-aged to 40 years and to 32% for cables pre-aged to 60 years. Another indication of potential reduced reliability of cables in harsh environments is the recent Sandia LOCA testing and observed failures of Okonite cables. It is difficult to draw strong conclusions based on the small sample size. These results lack unaged control samples for comparison. The testing does not approve or disapprove the adequacy of current qualification practices and requirements. However, these results should be a cause for concern since all risk-important operations in a harsh environment rely on cable performance.

Electrical Penetrations: Extensive qualification and research testing has been performed on electrical penetrations. The results indicated that, depending on the harshness of the environment, integrity can only be insured for time periods of 3 to 24 hours. Thus, failure probabilities in excess of those used in PRAs would be expected during the latter portions of exposure to a harsh environment. The major concern is that in-containment instrumentation circuits might provide erroneous readings if electrical penetrations have low insulation resistances between circuits or to ground. LOCA testing of electrical penetration assemblies (EPAs) performed at Sandia National Laboratory indicated a low insulation resistance for approximately 4% of the circuits early in the simulation and for approximately 85% of the circuits during post test cooldown. Post-examination of the electrical penetration feedthroughs suggested that degradation was aggravated by the accelerated aging exposures that preceded the harsh environment exposure.

Terminal Blocks: NRC inspections found use of unqualified terminal blocks even though utilities have replaced terminal blocks used in instrumentation circuits inside containment. In the presence of condensing steam, terminal block leakage is high. Hence, PRA failure probabilities that are based on normal operation performance of terminal blocks may be inappropriate to describe performance in harsh environments.

Transmitters: Test results suggest that transmitters may function with less reliability in ha environments than that assumed in PRAs. There are several NRC notices on transmitter operability such as installation problems affecting the differential pressure sensing lines and transmitter errors caused by thermal instability during the first hour of exposure to a harsh environment.

2.3 Issues associated with "old" EQ requirements

Plants designed, constructed, and licensed at different times have different guidance and requirements for the pre-aging, type testing, and documentation of electrical equipment component qualification. For example, in contrast to guidelines for later plants, guidelines for earlier plants do not require that samples for LOCA testing be pre-aged before testing. Also different samples are permissible for demonstrating resistance to aging stresses and resistance to a LOCA. Absence of voltage breakdown during the LOCA test of cables is considered acceptable with no examination or post-environmental test to demonstrate margi. Documentation required for the electrical equipment qualification of early plants can basica state that the tests were done.

Important issues, associated with "old" EQ requirements whose effect on equipment reliability in harsh environments needs to be evaluated, are listed below [2,3].

- Not taking into account aging (e.g., due to exposure to environmental and operation stressors such as temperature, radiation and humidity).
- Not taking into account synergistic effects (e.g, simultaneous exposure to radiation and steam as opposed to sequential exposure).
- Failure to demonstrate margin (to account for normal variations in commercial production of equipment and reasonable errors in defining satisfactory performance)
- Qualification by analysis (e.g. to demonstrate functional performance requirements of components).
- Functional and material similarity between installed and qualified components.
- Not taking into account installation practices during qualification (e.g., component orientation and interfaces).
- Not taking into account potential variations in electrical inputs during qualification (e.g., degraded voltage).

2.4 Risk-important electrical components with potentially reduced reliabilities in harsh environments due to issues associated with "old" EQ requirements

The following electrical components support risk significant operations in harsh environments. They also may have, as a result of the lower standards of "old" EQ requirements, reduced reliabilities when exposed to a harsh environment [2].

PWRs

- Solenoid and Motor Operators (including associated cables, connectors, penetrations, and valve position indication devices). Historically, PORV-related operators were not included in utility EQ master lists; have been the focus of NRC information notices, inspection findings and research programs; and are susceptible to aging which was not considered in plants with "old" EQ requirements.

- Steam Generator Level Detection Circuits. Typically consist of a differential pressure transmitter and associated connections, splices, cables, and electrical penetrations; and have been the focus of NRC information notices, inspection findings and research programs. They are susceptible to thermal degradation of transmitter electronics and age degradation of O-ring seal with subsequent moisture intrusion to the transmitter electronics.

BWRs

- Solenoid and Motor Operators (including associated cables, connectors, penetrations, and valve position indication devices).

3.0 PLANT SPECIFIC RISK ASSESSMENT

Three plants were selected for quantitative risk analysis. These include two PWRs (Sequoyah and Surry) and one BWR (Peach Bottom). Among the reasons for selecting these plants were the availability of PRAs [4], the availability of drawings showing components inside containment, they are representative of PWR and BWR plant populations, and they follow "old" EQ requirements.

Risk-important electrical components with potentially reduced reliabilities when operating in a harsh environment, common to all PWR plants, are: 1) electrical components supporting PORV and PORV block valve operations; and 2) steam generator level detector circuits. Similarly, risk-important electrical components with potentially reduced reliabilities when operating in a harsh environment, common to all BWR plants are: 1) electrical components supporting Safety Relief Valve (SRV) operations and 2) electrical components supporting Main Steam Isolation Valve (MSIV) and MSIV bypass operations.

A brief review of safety systems at several plants indicated a plant specific variation of components, inside the containment, in addition to the common components mentioned above, which may be important risk contributors if their reliabilities are reduced when they are required to operate in a harsh environment. Examples are:

- Sequoyah, Surry, and Indian Point: Normally closed MOVs are required to open, at approximately 15 hours into a large or medium LOCA, to provide hot leg recirculation.

- Indian Point 3: Two of the four pumps which are used for emergency core cooling during the recirculation phase of a LOCA, as well as their associated normally closed MOVs, are located inside containment. These pumps are required to operate in a harsh environment for several hours during a LOCA.

3.1 PWR Plant Specific Risk Assessment

Risk-important core damage sequences, and related in-containment components facing harsh environments, were identified. This was achieved by combining generic information from the literature review, presented in chapter 2.0, with plant specific information extracted from the Sequoyah and Surry PRAs [4]. These sequences, which are the same for both plants, are listed below.

1. Large and medium LOCAs with failure of hot leg recirculation: Hot leg recirculation is required at both plants at approximately 15 hours into the LOCA to prevent flow blockage due to concentration of boron in the reactor vessel. Affected in-containment components are:

- At Sequoyah, one normally closed motor-operated valve (MOV) is required to open, by remote manual actuation, at approximately 15 hours into the accident to allow low pressure recirculation through the hot legs. If this valve fails to open, the operator will try to use the safety injection pumps as a back-up.

- At Surry, one of two normally closed MOVs must open at approximately 18 hours into the LOCA, to provide hot leg recirculation.

2. Small and transient-induced LOCAs followed by failures of AFW and "feed and bleed" operation: In the event of small break or transient-induced LOCAs, core cooling is maintained by either high pressure injection and auxiliary feedwater (AFW) or by "feed and bleed" operation using high pressure injection and pilot-operated relief valves (PORVs). In-containment components affected by the harsh environment (for both Sequoyah and Surry) are:

    - Steam generator (SG) level detectors: failure to provide correct indication to the operator, at several hours into the LOCA, will impact AFW flow and possibly AFW operation.

    - PORV solenoid and block valve operators: common-cause failure would prevent PORVs and block valves to open for "feed and bleed" when demanded at several hours into the LOCA (following failure of AFW)

Current PRAs use normal operation statistics to model both the reliability of the AFW function and the "feed and bleed" function. However, both of these functions rely on operation of electrical components that are located in containment and hence subjected to the harsh environment caused by the small or transient-induced LOCA. The above accident sequences and associated affected components were used to conduct a screening evaluation of the potential risk impact of electrical components that were qualified according to "old" (i.e., DOR or NUREG-0588 Category II) EQ requirements. This was achieved by parametrically reducing the reliabilities of affected equipment to simulate the effect of potential common-cause failures in a harsh environment. It was assumed that the probability of AFW failure following incorrect SG level indications is 0.2. This implies that the operator can use alternative instrumentation effectively to control AFW flow following the failure of SG level detectors.

The results of the parametric risk analysis are presented in Table 1 for Sequoyah and Table 2 for Surry. The probability of failure of a single component when demanded, λ_D, was varied from 0.1 to 0.3. This reflects a subjective assessment of the qualitative information presented in Chapter 2. The percentage of all failures affecting single, redundant, components which are due to common-cause, β, was taken to be either 50% or 100%. This is consistent with the high probability assumed for single components which implies the presence of common-cause failure mechanisms. The product of λ_D and β gives the common-cause failure probability, λ_{cc},

Table 1. Core Damage Frequency (CDF) Increase Due to Common-Cause Failures of Electrical Components in a Harsh Environment for Sequoyah (Base Case CDF: 1E-4/yr).

AFFECTED SEQUENCES	AFFECTED COMPONENTS	SINGLE COMPONENT AND COMMON-CAUSE FAILURE PROBABILITIES			CDF INCREASE (per year)
		λ_D	β (%)	λ_{CC}	
Large and Medium LOCAs	Hot log recirculation MOV (fails to open)	0.1 0.2 0.3	- - -	- - -	2E-6 4E-6 6E-6
Small LOCAs	PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-5 2E-5 4E-5 6E-5
Transient-Induced LOCAs	PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-7 2E-7 4E-7 6E-7
All affected sequences	Hot leg recirculation MOV; PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-5 2E-5 4E-5 7E-5

Table 2. Core Damage Frequency (CDF) Increase Due to Common-Cause Failures of Electrical Components in a Harsh Environment for Surry (Base Case CDF: 2.5E-5/yr).

AFFECTED SEQUENCES	AFFECTED COMPONENTS	SINGLE COMPONENT AND COMMON-CAUSE FAILURE PROBABILITIES			CDF INCREASE (per year)
		λ_D	β (%)	λ_{CC}	
Large and Medium LOCAs	The two hot leg recirculation MOVs (fail to open)	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	5E-5 1E-4 2E-4 3E-4
Small LOCAs	PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-5 2E-5 4E-5 6E-5
Transient-Induced LOCAs	PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	2E-5 4E-5 8E-5 1E-4
All affected sequences	Hot leg recirculation MOVs; PORV solenoid operators; PORV block valve motor operators; SG level detectors	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	8E-5 2E-4 3E-4 5E-4

for redundant components (such as PORV solenoid operators and SG level detectors). Resulting plant core damage frequency increases vary from 1 x 10^{-5}/year to 7 x 10^{-5}/year for Sequoyah and from 8 x 10^{-5}/year to 5 x 10^{-4}/year for Surry. Such increases, which are comparable with NUREG-1150 estimates of base case core damage frequency for these plants, indicate that the risk impact of "old" EQ requirements can be significant if electrical component reliabilities are reduced due to the presence of a harsh environment.

3.2 BWR Plant Specific Risk Assessment

Risk-important core damage sequences, and related in-containment components facing harsh environments, were identified. This was achieved by combining generic information from the literature review, presented in chapter 2.0, with plant specific information extracted from the Peach Bottom PRA [4]. These sequences, are listed below.

1. Intermediate and small LOCAs followed by random failure of high pressure coolant injection (HPCI) and common-cause failure of the safety relief valves (SRVs) to open in a harsh environment: Opening of SRVs is required to depressurize the primary system so that low pressure coolant injection (LPCI) systems can be used to cool the core. Affected in-containment components are SRV solenoid operators whose failure will prevent SRVs to open when demanded, possibly at several hours into the LOCA.

2. Transient with loss of suppression pool cooling followed by common-cause failures of SRVs and MSIVs in a harsh environment (TW sequence): The MSIVs must open, in a harsh environment, to restore the power conversion system and thus avoid further heat-up of the suppression pool. Failure of the MSIVs would lead to failure of the HPCI/RCIC pumps (due to seal failure) and need to use the SRVs to depressurize and continue core cooling by low pressure injection. Failure of the SRVs to open in a harsh environment leads to core damage. Affected in-containment components are SRV and MSIV solenoid operators and MSIV bypass valve motor operators. SRV operation could be required for approximately 22 hours during the accident. Operation of MSIVs may be demanded any time before core melt.

The above accident sequences and associated affected components were used to conduct a screening evaluation of the potential risk impact of electrical components that were qualified according to "old" (i.e., DOR or NUREG-0588 Category II) EQ requirements. This was achieved by parametrically reducing the reliabilities of affected equipment to simulate the effect of potential common-cause failures in a harsh environment.

The results of the parametric risk analysis are presented in Table 3. The probability of failure of a single component when demanded, λ_D, was varied from 0.1 to 0.3. This reflects a subjective assessment of the qualitative information presented in Chapter 2. The percentage of failures affecting single, redundant, components that are due to common-cause, β, was taken to be either 50% or 100%. This is consistent with the high probability assumed for single components which implies the presence of common-cause failure mechanisms. The product of λ_D and β gives the common-cause failure probability, λ_{cc}, for redundant components (such as SRV solenoid operators, MSIV solenoid operators, and MSIV bypass valve motor operators). Resulting plant core damage frequency increase estimates vary from 1 x 10^{-5}/year to 1 x 10^{-4}/year. Such increases, which are comparable with the NUREG-1150 estimate of base case core damage frequency for Peach Bottom, indicate that the risk impact of "old" EQ requirements can be significant if electrical component reliabilities are reduced due to the presence of a harsh environment.

Table 3. Core Damage Frequency (CDF) Increase Due to Common-Cause Failures of Electrical Components in a Harsh Environment for Peach Bottom (Base Case CDF: 8E-6/yr).

AFFECTED SEQUENCES	AFFECTED COMPONENTS	SINGLE COMPONENT AND COMMON-CAUSE FAILURE PROBABILITIES			CDF INCREASE (per year)
		λ_D	β (%)	λ_{cc}	
Intermediate and Small LOCAs	SRV solenoid operators	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	3E-6 6E-6 1E-5 2E-5
Transient with loss of suppression pool cooling (TW sequence)	SRV and MSIV solenoid operators and MSIV bypass valve motor operators	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-5 2E-5 4E-5 6E-5
All affected sequences	SRV and MSIV solenoid operators and MSIV bypass valve motor operators	0.1 0.2 0.2 0.3	50 50 100 100	0.05 0.1 0.2 0.3	1E-5 3E-5 5E-5 1E-4

4.0 CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

The major conclusions from this preliminary risk analysis are summarized below.

- Core damage frequency estimates for both PWR and BWR plants could increase significantly if electrical equipment reliabilities are reduced due to the presence of a harsh environment.

- Current PRA perceptions regarding important risk contributors could change if electrical equipment reliabilities are reduced due to the presence of a harsh environment.

- The magnitude of core damage frequency impact is plant specific.

- Due to the lack of reliability data bases and the limitations in current PRA models, an accurate assessment of the risk associated with harsh environments is not possible at this time.

The following future work is recommended.

- Identify potential failure modes of aged in-containment electrical equipment required to be able to function in harsh environments.

- Devise a grouping scheme for electrical equipment in harsh environments to guide the selection of failure probabilities for the several failure modes. Such a scheme could be based on expert elicitation using available information (e.g., failure modes and associated stressors, failure mechanisms, and degradation sites as well as other available qualitative information on "old" EQ requirements and specific component vulnerabilities) and substituted for the lack of reliability data bases.

- Assess the likelihood that a failure of an in-containment electrical component is propagated to components outside containment (e.g., due to failure of protective devices, miscoordination among circuit breakers of different sizes, erroneous signals, etc.).

- Assess the need for human reliability analysis which takes into account the presence of erroneous indications, failure of required automatic actuations as well as the presence of undesirable actuations.

- Use the above mentioned information in accident scenarios associated with harsh environmental conditions to obtain more realistic estimates of the increases in core damage frequency and better insights regarding the risk significance of electrical equipment EQ issues.

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US Nuclear Power Plants—Showing Their Age

Case Study: Core Shroud Cracking

By Robert Pollard

Union of Concerned Scientists

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Robert Pollard is senior nuclear safety engineer at the Union of Concerned Scientists.

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Abstract

As more nuclear power plants approach middle age, it is becoming increasingly clear that a wide variety of degradation mechanisms pose significant economic and safety risks. Since the Nuclear Regulatory Commission (NRC) confirmed that age-related degradation in boiling water reactors (BWRs) will damage or destroy vital internal components well before the standard 40-year BWR license expires, federal regulators must now seriously address the future safety and engineering implications of multiple component failures in BWRs. State regulators must also take a long-range view and reexamine the cost-effectiveness of their current response to the aging-reactor crisis—a response that favors a piecemeal, fix-or-replace-at-any-cost strategy. And they must put in place the necessary financial incentives to minimize future costs to their customers without compromising nuclear plant operating safety standards.

This paper focuses on just one age-related problem confronting the nuclear power industry: degradation of the internal components in BWR pressure vessels. This study found that the nuclear industry—the regulated and the regulators alike—is not prepared to deal with the grave age-related problems that lie ahead. Prudent officials at all levels of government need to adopt a broad-gauged management plan to meet current and future engineering and economic challenges. A piecemeal, one-component-at-a-time approach may have been appropriate in the past, but it is simply no longer in the public interest, nor in the interest of the nuclear industry, to continue in this manner.

Introduction

Since 1978 no new nuclear reactors have been ordered in the United States, and plant orders placed between 1973 and 1978 have been canceled. Today, the US nuclear power industry is trying to survive by finding ways to extend the useful life of existing nuclear power plants another 20 years beyond their initial 40-year license period. This is an outdated strategy, and one that the Nuclear Regulatory Commission's own nuclear plant aging research program severely discredits.

Research has shown that a multitude of both large and small nuclear plant components are susceptible to a staggering variety of aging mechanisms. Reactor vessels, steam generators, piping, valves, heat exchangers, pumps, motors, instrumentation, electrical cables, seals, and supports are all degraded by erosion, fatigue, corrosion, radiation and thermal embrittlement, and vibration.

Studies have also demonstrated that some types of degradation cannot be detected using the established methods of periodic testing and inspection. Furthermore, in some cases no known methods exist for detecting the degradation. In-service failures in BWRs are thus inevitable.

To date, the single most significant finding resulting from the NRC's research program is that the essential conditions that produce stress corrosion cracking—including corrosion-susceptible materials, a corrosive environment, and tensile stresses—are *all* present in BWRs. So far, most of the documented cracking has been found in one component, the core shroud. But 18 other BWR internal components are also known to be susceptible to stress corrosion cracking. In all, 21 major BWR internal components are susceptible to corrosion, fatigue, creep, embrittlement, and erosion, or to a combination of these degradative mechanisms.

Other worrisome NRC findings include the following:

- Most BWRs experience core shroud cracking after only 20 years of operation—not 40 or 60
- The synergistic effects of multiple degraded components is still a largely unexplored but critical aspect of the BWR aging cycle

The Genesis of the Problem

In a January 4, 1994, internal memorandum (cited on page 1 of the attachment to SECY-94-276, dated Nov. 10, 1994), the NRC declared core shroud cracking in BWRs to be "an emerging technical issue." Since that date, the NRC has focused on core shroud cracking as a safety issue, and industry officials have busied themselves looking for reliable ways to find the cracks and then develop a technical fix for the problem. This approach, however, is not so much wrong as it is seriously incomplete.

By placing top priority on the more immediate safety implications associated with cracks in the core shroud—a legitimate concern given the NRC's charter—industry and NRC officials have implicitly elected to follow a piecemeal strategy for dealing with a broad range of age-related BWR issues. The industry and its regulators appear to be deliberately avoiding a comprehensive, systemwide, long-range approach.

On two counts, this is a dangerous precedent. First, once removed from its larger context, the true significance of the failure of any one component will be greatly underestimated, as will the synergistic effects that are likely when two or more components simultaneously experience a failure.

Second, a piecemeal approach can only treat the symptoms of a problem, not the problem itself. The root problem facing the BWR industry is not cracks in the core shroud or degradation in any of the other two dozen internal components of the reactor vessel known to be susceptible to stress corrosion cracking, creep, fatigue, embrittlement, and erosion; nor is it any one of the multiple valves, motors, pipes, seals, supports, and electrical wires that are experiencing age-related degradation. The real—and thus far neglected—problem facing federal and state-level regulators is that they don't have a detailed picture of the long-term cost-effectiveness and reliability implications of the nation's aging BWR plants. Only when regulators have such a picture can they make sense of what cracks in the core shroud and other aging problems really mean to utilities and their customers—and only then can they make enlightened decisions in the public interest.

Technical Background

The Core Shroud

As shown in figure 1, the core shroud is a 360-degree stainless steel cylinder surrounding the BWR core. Typically, a core shroud will measure 20 feet in height, 14 to 17 feet in diameter, and 1.5 to 2.0 inches in thickness. The core shroud performs three primary functions. First, it directs the incoming feedwater down and along the reactor vessel's wall, and then up through the reactor's core. Second, in addition to supporting the reactor's top guide and core plate, the core shroud also maintains the reactor's core geometry under normal operations. Finally, the shroud provides a refloodable space that could help protect the core from damage during an accident.[1]

Core Shroud Cracking

Table 1 is a compilation of core shroud inspection data received by the NRC from BWR operators. The primary locations for intergranular stress corrosion cracking in the core shroud are along the nine circumferential weld lines shown in figure 2. Figure 3 demonstrates that cracks in the core shroud are directly linked to the aging process. In BWRs in commercial operation for fewer than 20 years, core shroud cracking is rare. After 20 years, moderate to extensive cracking is the rule rather than the exception.

[1] For further details on the role of the core shroud and other BWR internal components, see Nuclear Regulatory Commission, *Boiling-Water Reactor Internals Aging Degradation Study,* NUREG/CR-5754, September 1993.

Figure 1

BWR INTERNAL COMPONENTS

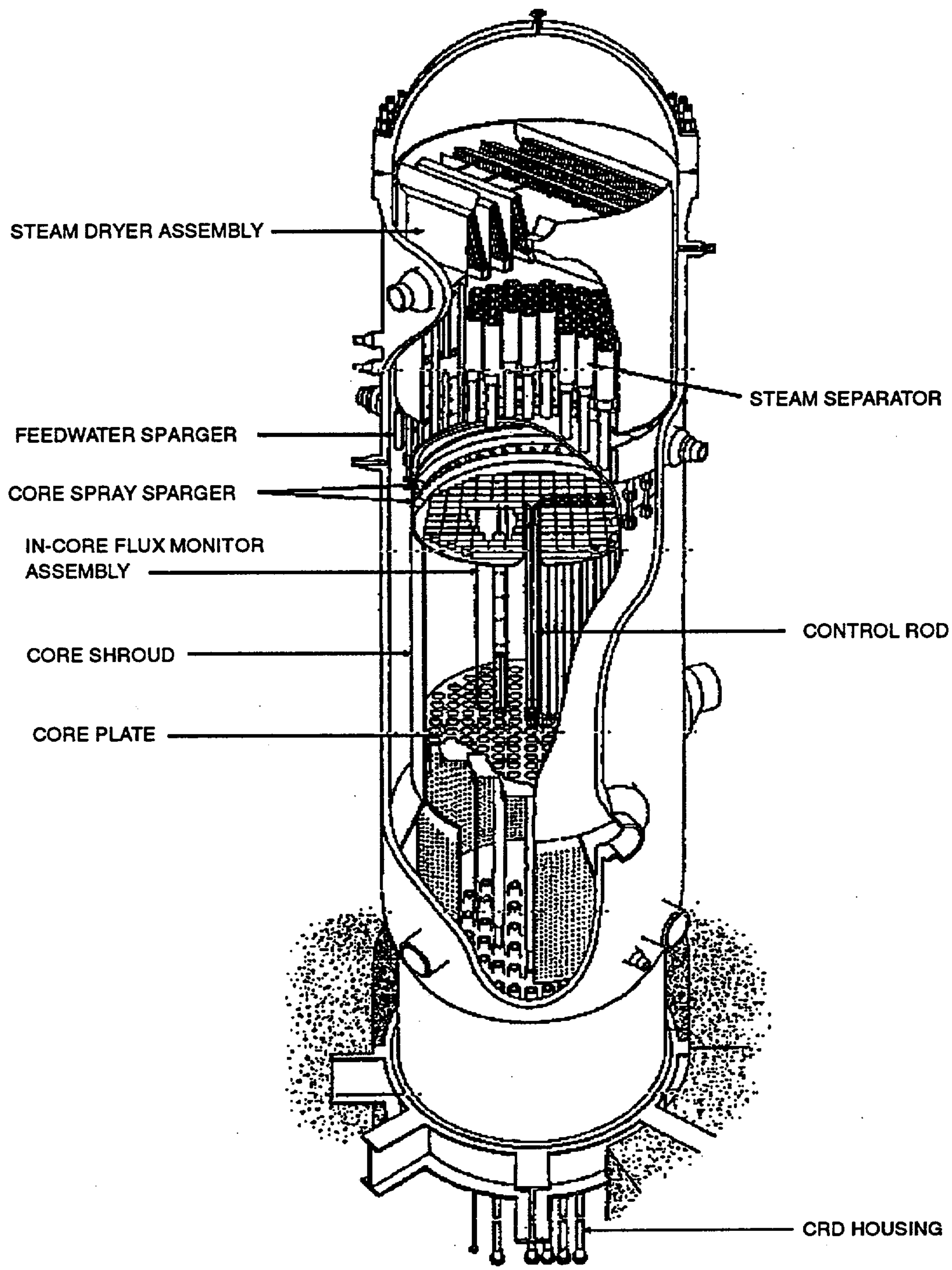


Table 1

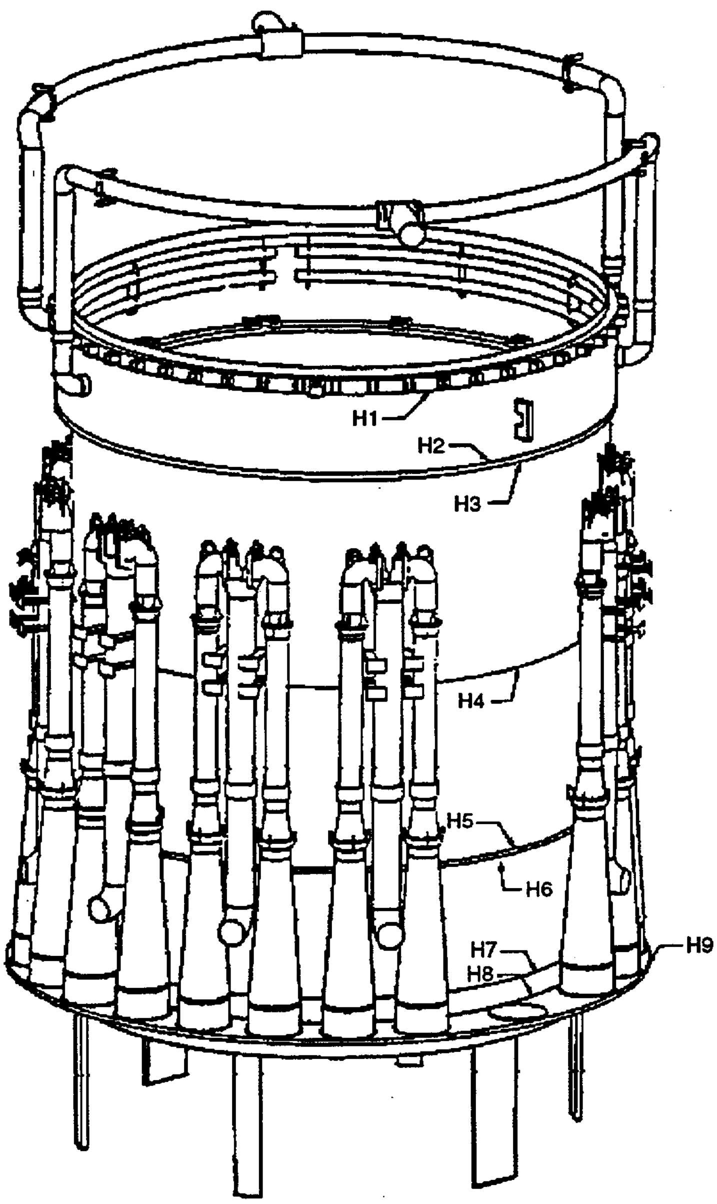
SUMMARY OF NRC DATA ON CORE SHROUD CRACKING

Plant	Type	Commercial Operation	Last Inspection	Summary
Brunswick 1	MK 1 BWR-4	3/18/77	10/93	Inspection found extensive cracking. Repairs have been implemented.
Brunswick 2	MK 1 BWR-4	11/3/75	5/94	Inspection found extensive cracking. Repairs have been implemented.
Peach Bottom 2	MK 1 BWR-4	7/5/74	9/94	Moderate cracking found without significant degradation of shroud structural integrity.
Peach Bottom 3	MK 1 BWR-4	12/23/74	11/93	Minor circumferential and axial cracking found.
Nine Mile Pt 2	MK 2 BWR-5	3/11/88	11/93	Inspection found no cracking.
Vermont Yankee	MK 1 BWR-4	11/30/72	10/93	Inspection found no cracking.
Millstone 1	MK 1 BWR-3	3/01/71	1/94	Minor circumferential cracking found.
Hatch 2	MK 1 BWR-4	12/31/75	4/94	Inspection found moderate cracking.
Oyster Creek	MK 1 BWR-2	12/1/69	10/94	Inspection found extensive cracking. Repairs have been implemented.
Dresden 3	MK 1 BWR-3	11/16/71	4/94	Inspection found extensive cracking. A safety evaluation justified continued operation for 15 months without repair.
Quad Cities 1	MK 1 BWR-3	2/18/73	4/94	Inspection results similar to Dresden 3.The Dresden 3 safety evaluation covered Quad Cities continued operation for 15 months.
Fermi 2	MK 1 BWR-4	1/23/88	6/94	Inspection found minor axial cracking.
Monticello	MK 1 BWR-4	6/30/71	10/94	Inspection found minor circumferential cracking.
Duane Arnold	MK 1 BWR-4	2/01/75	9/93	Inspection found no cracking.
Hope Creek	MK 1 BWR-4	12/20/86	3/94	Limited inspection found no cracking.
LaSalle 1	MK 2 BWR-5	1/01/84	5/94	Inspection found no cracking.
Perry 1	MK 3 BWR-6	11/18/87	5/94	Inspection found no cracking.
Susquehanna 1	MK 2 BWR-4	2/12/85	12/93	Inspection found no cracking.
WPN-2	MK 2 BWR-5	12/13/84	6/94	Limited inspection found no cracking.

Source: *NRC Report to Congress on Abnormal Occurrences for October–December 1994*, March 1995

Figure 2

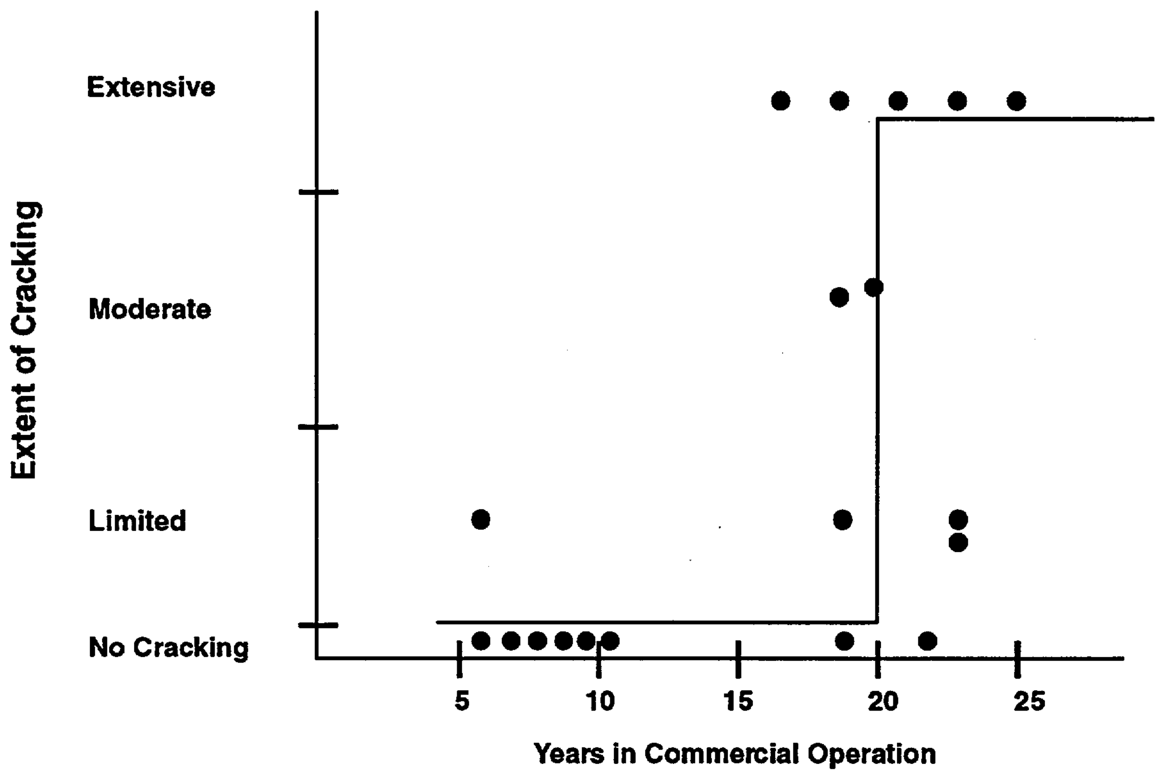
CORE SHROUD WELD LOCATIONS



Source: NRC Generic Letter 94-03, July 25, 1994

Figure 3

SUMMARY OF NRC DATA ON CORE SHROUD CRACKING



Source: Data from *NRC Report to Congress on Abnormal Occurrences for October–December 1994*, March 1995

The Core Shroud in Context

In its March 15, 1995, *Report to Congress on Abnormal Occurrences for October–December 1994*, the NRC called BWR core shroud cracking "the most significant concern related to potential failure of reactor internals reported during 1993 and 1994." Although cracks in the core shroud have deservedly received a good deal of attention in recent years, it is crucial to keep a systemwide perspective. Core shroud cracking is indeed a very serious problem but, more important, it is a harbinger of even more widespread future crises. As the BWR fleet continues to age, component failures will become more and more commonplace. The current core shroud crisis should be thought of as a wake-up call rather than an opportunity to find and apply a technological quick fix.

Table 2 (on page 8) puts the core shroud into a far more meaningful context. Since the core shroud is but one internal component among many that will fail with the passage of time, this table underscores the dangers associated with addressing the core shroud apart from its larger BWR context. The core shroud may be the first internal failure to come to the attention of state, NRC, and industry officials, but it will surely not be the last.

As shown in table 2, 19 of the 21 BWR internal components listed are susceptible to stress corrosion cracking, including irradiation-assisted intergranular stress corrosion cracking. In addition, eight components are vulnerable to fatigue failures. Embrittlement is a potential aging-related degradation mechanism for four components, and erosion causes degradation in two components. Finally, five internal components are susceptible to the effects of creep.

Synergistic Effects

Significantly, in addition to the core shroud, 10 other internal components listed in table 2 are susceptible to two or more aging-related degradation mechanisms. In the past two years, NRC and industry officials have worked long and hard to accumulate a spattering of data concerning how and why the core shroud is cracking, and what to do about it. But to date, little is known for sure about the synergistic effects of the degradation and failure of one internal component as it interacts with others. Rather conservative speculation, however, would raise the following domino-like risks:

- The force of escaping water from a ruptured pipe could cause a nearby, previously cracked component—such as a top guide—to fail and thereby prevent the insertion of control rods, which in turn would stop the reactor's shutdown

- The failure of *any* component listed in table 2 could very well block the flow of water within the core, resulting in a localized melting of the reactor's fuel

Even under ideal conditions, detecting damaged internal components is an uncertain task. Access to the components is limited, and inspection techniques, visual and ultrasonic alike, are not 100 percent accurate. What is certain, however, is that with the passage of time the five degradation mechanisms and the 21 internal components listed in table 2 will interact with one another in surprising and unpredictable ways.

Reactor Repairs: The State of the Art

The Core Shroud

What does it take to repair a cracked core shroud in terms of cost, plant down time, and technology availability? According to the February 6, 1995, issue of *Inside NRC,* MPR Associates, based in Alexandria, Virginia, has developed a recently patented core shroud repair method, which consists of a series of 10 vertically mounted tie-rods applying axial compression to a cracked shroud. MPR charges between $500,000 and $1 million to inspect a core shroud, and $3 million to $4 million to install the tie-rods. The repair reportedly takes about 10 days.

Table 2

BWR INTERNAL COMPONENTS AND POTENTIAL AGING-RELATED DEGRADATION MECHANISMS

Component	SCC[a]	Creep[b]	Fatigue[c]	Embrittlement[d]	Erosion[e]
Steam dryer			●		
Steam separator	●			●	●
Shroud head	●				
Shroud head bolts	●				
Steam separator support ring	●				
Top guide	●	●			
Access hole cover	●				
Core shroud	●	●			
OFS piece	●	●		●	
Core plate	●				
Core spray line internal piping	●				
Core spray sparger	●		●		
Feedwater sparger	●		●		
Jet pump	●		●	●	●
In-core neutron flux monitor housings	●		●		
In-core neutron flux monitor guide tubes	●		●		
In-core neutron flux monitor dry tubes	●	●	●		
CRD housing	●				
Neutron source holder	●				
Jet pump sensing line			●		
Control blade	●	●		●	

Source: *Boiling-Water Reactor Internals Aging Degradation Study,* NUREG/CR-5754, September 1993

[a]**Stress Corrosion Cracking.** SCC refers to the weakening of a BWR internal structural component because of deterioration caused by electrochemical reactions with the surrounding material.

[b]**Creep.** The progressive deformation of a structure under constant stress is known as creep.

[c]**Fatigue.** As a structure vibrates in response to dynamic loads, cracks develop in certain BWR internal components.

[d]**Embrittlement.** Exposure of internal components to high temperatures (thermal embrittlement) and prolonged exposure to fast neutron fluxes (radiation embrittlement) make a material more brittle and vulnerable to cracking.

[e]**Erosion.** The abrasive effects of bubbles and droplets in a liquid flow can weaken BWR internal components.

Other Internal Components

The readiness of the industry to meet projected maintenance and repair challenges that lie ahead is unclear. A rough measure of the nuclear industry's level of readiness to manage the full range of problems associated with aging BWRs is found in a June 1994 report of the Boiling Water Reactor Owners Group. As indicated in table 3, more than half of the internal components in a BWR are classified as readily repairable. But, for 12 of 29 components (bolded below), repair methodologies were still in the conceptual phase of development.

Table 3

OTHER REACTOR INTERNALS REPAIR OPTIONS

Component	Repair Capability
Shroud support	N
Jet pump	C
Control rod drive	R
Control rod guide tube	R
Control rod drive housing/stub tube	Y
In-core housing	Y
Head cooling spray nozzle	R
Core delta pressure and liquid contr ol line	C
LPCI coupling	N
Core spray line	Y
Jet pump riser brace	Y
Orificed fuel support	R
Access hole cover	Y
Top guide	C
-Keeper	C
-Bolt	C
-Wedge	C
-Aligner	C
Core plate	C
-Bolt	C
Shroud	Y
Core spray sparger	Y
Dry tube	R
Reactor Vessel Attachments	
Steam dryer hold down bracket	X
Steam dryer support bracket	X
Guide rod bracket	X
Feedwater sparger	X
Core spray line bracket	X
Surveillance capsule holder brac ket	N

Y = local repair or replacement available
N = no repair developed to date
R = replaceable component
C = conceptual repair (design of hardware and installation tooling not complete)
X = hands-on repair possible after lowering vessel water

Source: NRC/BWROG meeting materials, June 28, 1994

Looking Toward the Future

Faced with long-term economic and technological uncertainty, the BWR community—owners, suppliers, and regulators at all levels of government—can no longer afford a myopic, short-term view of the future. Indeed, Ivan Selin, then-departing chairman of the NRC, warned in a May 9, 1995, address that reactor aging will require a major, continuous effort by industry officials to anticipate emerging aging-related problems and to resolve them before they become a crisis.

A comprehensive analysis of the BWR aging problem, taken as a whole, is a good place to start. Such a plan must include:

- a complete technical feasibility study of the life-cycle of each and every BWR internal component subject to failure. Knowing that 60 percent of the components can be repaired, given the state of the art, is not good enough;

- a detailed, component-level economic strategy to guide state regulatory decisions about when a BWR is economically repairable, and when it is beyond repair.

The nuclear industry can no longer afford, technically or financially, to muddle forward into the 21st century. The most important way for the BWR community to begin today to make better decisions tomorrow is to deal with the whole problem of aging-related degradation.

US Nuclear Power Plants—
Showing Their Age

Case Study: Reactor Pressure Vessel Embrittlement

By Robert Pollard

Union of Concerned Scientists

December 1995

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Robert Pollard is senior nuclear safety engineer for the Union of Concerned Scientists.

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Abstract

As more nuclear power plants approach middle age, it is becoming increasingly clear that a wide variety of degradation mechanisms pose significant economic and safety risks. One such mechanism, radiation-induced embrittlement of the reactor pressure vessel, affects all US nuclear power plants and becomes progressively more severe the longer a reactor is operated. More than a decade after the US Nuclear Regulatory Commission (NRC) expressed confidence that the vessel embrittlement problem was well understood, operating experience and new information show the opposite. State regulators should plan for the possibility that vessel embrittlement may cause more plants to close permanently before expiration of their 40-year operating licenses and is likely to preclude extending the operating licenses of other plants.

Economic implications aside, embrittlement of reactor pressure vessels also poses serious safety risks. It could lead to rupture of a reactor vessel—an accident more severe than safety systems are designed to mitigate. Although some plants have taken steps to slow the rate of embrittlement, the problem has not been eliminated. The NRC must discontinue its practice of relaxing safety requirements or ignoring violations of its regulations. Public safety requires strict enforcement of the rules governing inspections of reactor vessels for cracks and those governing the maximum permissible vessel embrittlement. State regulators should recognize that methods to counteract the effects of embrittlement are unproven and that vessel embrittlement may require early decommissioning of nuclear plants. Thus, before authorizing major expenditures for repairs or plant modifications unrelated to vessel embrittlement, regulators must consider whether permanent closure of the plant is the better economic choice for electricity consumers.

Introduction

In 1992, embrittlement of the reactor pressure vessel beyond safety limits led to the permanent shutdown of the Yankee Rowe plant in western Massachusetts after 31 years of operation—at the time, the longest that any US nuclear power plant had operated. Today, it is uncertain whether reactor vessel embrittlement or some other age-related mechanism will make the remainder of America's aging nuclear power plants too dangerous or too costly to continue operation. What is certain is that degradation of reactor pressure vessels will become more severe as our nuclear power plants age. Federal and state regulators must face this reality if they are to act in the best interests of the public.

Embrittlement of reactor pressure vessels is a particularly serious safety problem because no safety systems are capable of protecting the public against the consequences of vessel failure. The emergency core cooling systems are designed to prevent a meltdown if an accident involves a break in a pipe connected to the reactor. But these systems were not designed to prevent a meltdown if the reactor vessel ruptures. Furthermore, the containment building housing the reactor is not designed to remain intact in the event of a reactor meltdown. Thus, failure of a reactor pressure vessel could result in off-site releases of radiation as large as, or larger than, the releases estimated to have occurred at Chernobyl.

Determining the magnitude of the risk posed by vessel embrittlement is an uncertain process. The rate of embrittlement varies widely from plant to plant. Small variations in the chemical composition of vessel materials, the operating temperature of the reactor, the distribution of uranium in the reactor core, and the distance between the core and the vessel wall all have an effect on the rate of degradation. Further, the lack of an inexpensive and reliable method to locate and determine the size of cracks or other flaws in the reactor vessel undermines the reliability of calculations to determine the probability of vessel failure. Measuring the amount of embrittlement requires destructive testing of vessel materials, but some plants do not have representative samples of the vessel materials needed for such testing. Thus, a plant-specific analysis is needed to evaluate the magnitude of the safety hazard posed by embrittlement of the reactor pressure vessel and to estimate the remaining useful life of the nuclear power plant.

A variety of techniques can be employed to reduce the rate of vessel embrittlement and, theoretically, some effects of the radiation damage could be reduced. These techniques are, however, either of limited value or their efficacy and cost are unknown. In particular, the nuclear industry and the Nuclear Regulatory Commission (NRC) have claimed that heating the reactor vessel far above its normal operating temperature could restore the reactor vessel to near its pre-irradiated condition. Heat treatment of a reactor vessel has never been attempted on a US plant, however, and thus its cost and effectiveness remain unknown.

Technical Background

The Reactor Pressure Vessel

This paper focuses on embrittlement of the reactor pressure vessels in pressurized water reactors (PWRs)—the type of reactor used in 73 of the 110 licensed US nuclear power plants. Although the reactor vessels in plants using boiling water reactors also become embrittled, the problem is, in general, less severe in those plants.

The typical reactor pressure vessel used for pressurized water reactors is a massive steel container about 40 feet tall and 15 feet in diameter, as shown in figure 1. It is constructed of steel plates about 8 inches thick, which are held together by circumferential and axial welds. The inside surface is clad with stainless steel to reduce corrosion.

The reactor pressure vessel in a PWR is normally completely filled with water to keep the fuel core covered. The reactor and the piping connected to it form the reactor coolant pressure boundary, containing the reactor cooling water under a pressure of about 2,200 pounds per square inch.

Reactor Vessel Embrittlement

The reactor pressure vessel becomes embrittled by exposure to neutron radiation from the fission process in the core. The portion of the vessel walls and welds directly opposite the reactor core—the vessel beltline region—receives the highest level of radiation exposure. Vessel embrittlement occurs when long exposure to radiation reduces the ability of the vessel materials to give, or stretch. As the vessel's steel plates and welds become brittle, they are more likely to fracture.

The chemical composition of the vessel materials is a key factor affecting the extent to which the vessel becomes embrittled by the neutron radiation. The presence of small amounts of copper and nickel in the irradiated material—less than 1 percent by weight—can have a marked effect on the magnitude of embrittlement degradation. For example, increasing the amount of copper in the vessel welds by just a few hundredths of a percent can reduce the time to reach embrittlement limits by several years.

Another factor that affects the rate of vessel embrittlement is the temperature at which the reactor operates. For a given radiation exposure, a vessel will become embrittled at a faster rate if it operates at a lower temperature. Thus, if reactors are operated at a lower temperature in an attempt to slow the rate of corrosion in other components, such as steam generator tubes, the result is more embrittlement.

Reference Temperature

The characteristics of the vessel materials change as the reactor vessel is heated. The temperature at which this change in material properties occurs is known as the reference temperature. At temperatures below the reference temperature, the steel plates and welds are brittle and subject to cracking, like glass. Above the reference temperature, the materials are ductile and are able to stretch when subjected to stress. The effects of temperature and neutron radiation on the reactor vessel are shown in figure 2 below.

Figure 1

Typical PWR Reactor Pressure Vessel

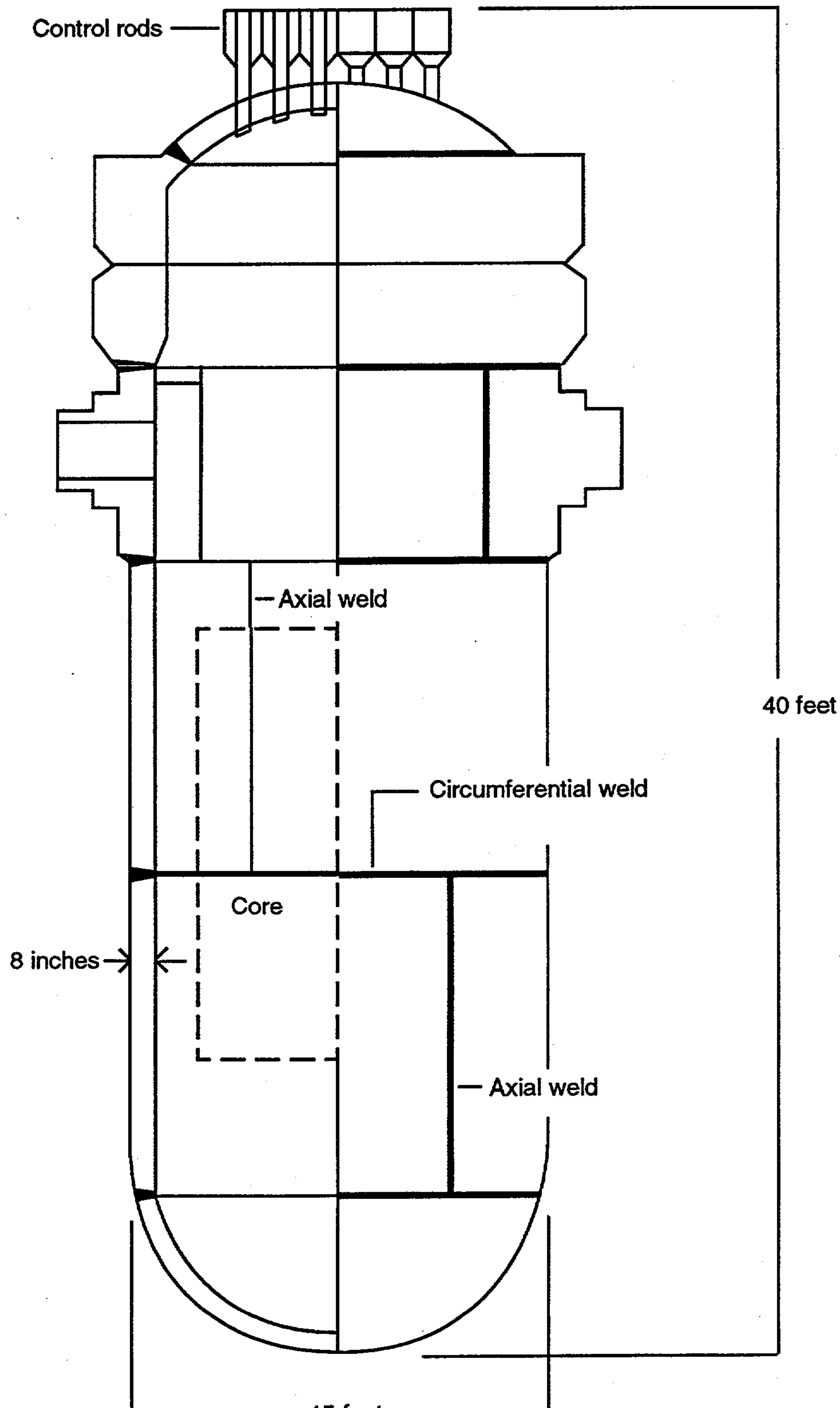
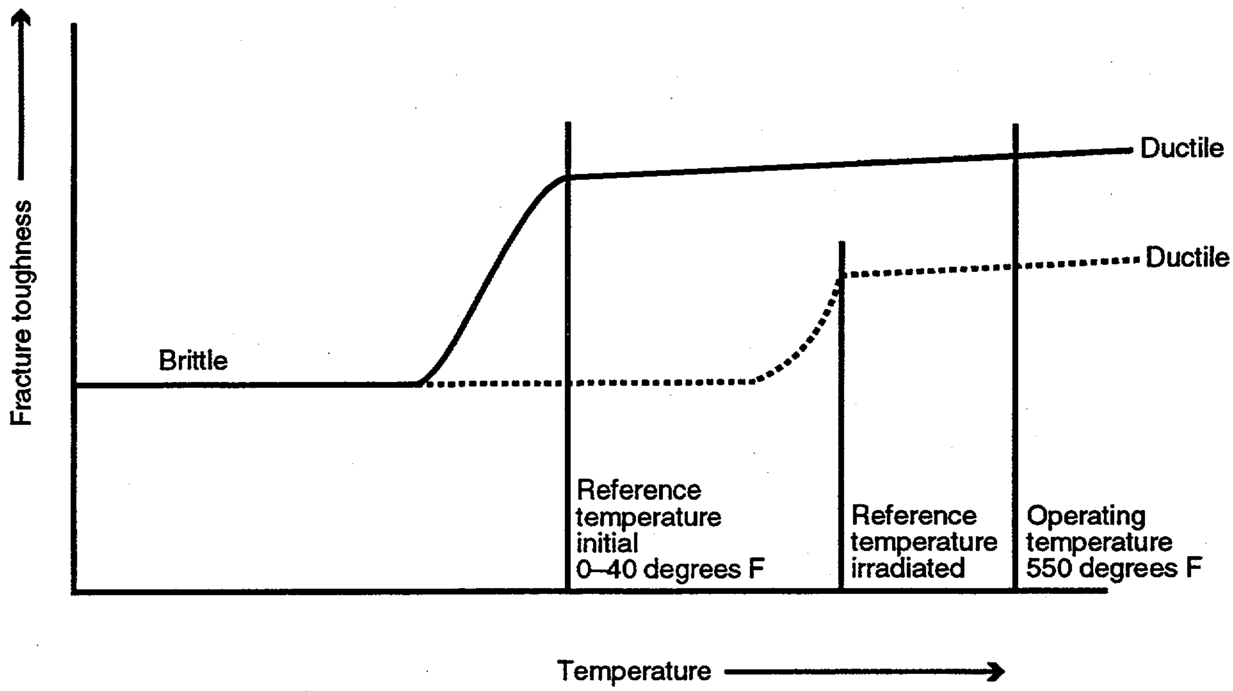


Figure 2

Effects of Radiation on Reactor Pressure Vessel



In a new vessel, the reference temperature is in the range of 0 to 40 degrees Fahrenheit. As the vessel materials are bombarded by high energy neutrons during the life of the plant, however, the reference temperature gradually increases. This aging process reduces the safety margin between the temperature at which the vessel exhibits brittle characteristics and the temperature to which the vessel will be cooled in the event of an accident. Thus, the longer the reactor operates, the higher the reference temperature becomes and the more susceptible the vessel is to fracture in the event of an accident.

Current NRC regulations limit the reference temperature to less than 270 degrees Fahrenheit for the vessel's steel plates and axial welds, and to less than 300 degrees Fahrenheit for the vessel's circumferential welds.

Fracture Toughness

In addition to the increase in the reference temperature, neutron irradiation causes a reduction in the reactor pressure vessel's "fracture toughness"—the ability of the steel and weld materials to resist fracture—even at the normal operating temperature of 550 degrees Fahrenheit. Over time, as the damage from the neutron radiation accumulates, the vessel's resistance to fracture decreases.

Fracture toughness is determined by measuring the energy required to break samples of the steel plates and welds originally used in the fabrication of the reactor vessel. Samples of the original materials are supposed to be saved and hung inside the reactor vessel so that they are exposed to the level of radiation reaching the vessel wall. As the plant ages, the samples are periodically removed and tested to determine the extent to which the vessel has become embrittled.

Current NRC regulations specify that reactor vessel plates and welds must have an initial fracture toughness of at least 75 foot-pounds and must maintain a fracture toughness of no less than 50 foot-pounds throughout the life of the reactor pressure vessel.

Pressurized Thermal Shock

During normal operation, the pressure vessel is heated to approximately 550 degrees Fahrenheit, the operating temperature of the reactor cooling system. In the event of accident, however, the emergency core cooling systems inject relatively cold water—less than about 100 degrees Fahrenheit—into the reactor vessel. If the accident involves a small pipe break or steam generator tube leak, the emergency cooling systems will also rapidly repressurize the reactor to a pressure of about 2,500 pounds per square inch. This combination of rapid cooling and pressurization is referred to as "pressurized thermal shock" of the reactor pressure vessel, which can cause cracking or rupture of an embrittled vessel. Vessel failure is even more likely if a small crack or some other flaw is present.

For most nuclear plant accidents, the NRC employs a "defense-in-depth" strategy for protecting the health and safety of the public. Redundant safety systems are provided so that if one system fails, another may be available. No such backup is available for the pressure vessel, however. If it fails, there is no means of cooling the core and avoiding a meltdown because the emergency cooling water escapes from the vessel without reaching the core. Since the containment building is not designed to withstand a meltdown, such an event would probably lead to a release of intensely radioactive material from the molten core into the environment.

Crack Detection

To ensure the structural integrity of a reactor pressure vessel, it is essential that it be inspected to determine the location, size, and orientation of any flaws, such as cracks. NRC regulations require that such inspections be performed about once every 10 years. The ultrasonic testing methods used for these inspections are not particularly reliable, however, and some portions of the vessel wall cannot be inspected at all because of physical obstructions. The NRC's Regulatory Guide 1.150 on ultrasonic testing of reactor vessels notes that the "lack of reliability of UT [ultrasonic testing] examination results is partly due to the reporting of ambiguous results, such as reporting the length of flaws to be shorter during subsequent examinations." Given such limitations, it is difficult to make an accurate determination of whether cracks are present in the vessel or, if so, the rate at which the cracks are growing.

History of NRC Regulations and Enforcement

Because no safety system exists to protect the public in the event of pressure vessel failure, the NRC issued regulations intended to ensure that the probability of failure of the reactor pressure vessel is and remains extremely low. To achieve this goal, the NRC envisioned both (1) early detection of flaws or cracks developing in the vessel wall, and (2) periodic measurements of the extent to which the material used to fabricate the vessel is becoming embrittled. These regulations were developed in order to prevent the deadly consequences of pressure vessel embrittlement and rupture and constitute the NRC's minimum standards that plants must meet to provide reasonable assurance of public safety.

Lax Enforcement of NRC Regulations

The NRC adopted regulations that became effective in August 1973 and remained in effect until the mid-1980s, when they were amended. The 1973 regulations stated that the vessel's maximum reference temperature at the end of a plant's life should be less than 200 degrees Fahrenheit. If the reference temperature was predicted to exceed 200 degrees Fahrenheit, the plant was required to be designed to permit heat treatment of the vessel at a sufficiently high temperature to recover material toughness properties. In 1981, the NRC staff informed the NRC chair that the owners of certain plants—those licensed before August 1973 in which the predicted end-of-life reference temperature was greater than 200 degrees Fahrenheit—claimed that they had the capability to perform such a heat treatment. In reality, neither the nuclear industry nor the NRC performed more than superficial evaluation of the feasibility and effectiveness of heat treating the reactor pressure vessel, regardless of the date the plants were licensed.

After the plants were licensed for operation, the reactor vessels became embrittled faster than had been predicted. In addition, evaluations of accidents at operating plants involving pressurized thermal shock of the vessel showed that if those accidents were repeated at an older plant with an embrittled reactor pressure vessel, there was a high probability that the vessel would rupture.

In July 1981, the NRC ordered 44 operating plants to determine the condition of their reactor vessels. The results of these evaluations, published in November 1982 as *NRC Staff Evaluation of Pressurized Thermal Shock*, showed that the reference temperature of the vessels at 15 operating plants (see table 1) exceeded 200 degrees Fahrenheit. Most of the those plants had operated for less than 10 years (and three—Rancho Seco, San Onofre 1, and Yankee Rowe—are no longer in operation).

The NRC did not order these 15 plants shut down to perform a heat treatment of the vessel. Instead, in February 1984, the agency published a proposed rule to establish new limits on reference temperature—270 degrees Fahrenheit for the vessel plates and axial welds and 300 degrees Fahrenheit for the circumferential welds (49 Fed. Reg. 4500). The Commission proposed these higher temperature limits despite an NRC contractor's report that said it would be "unwise" to do so. The NRC portrayed the proposed rule changes as "intended, if adopted, to produce an improvement in the

Table 1

Plant	Location	Max. Ref. Temp (as of 12/81)	Began Operation (year)
Cook 1	Mich.	200 °F	1974
Fort Calhoun	Nebr.	242 °F	1973
Ginna	N.Y.	213 °F	1969
Indian Point 3	N.Y.	212 °F	1976
Oconee 2	S.C.	231 °F	1973
Point Beach 1	Wis.	210 °F	1970
Point Beach 2	Wis.	215 °F	1971
Rancho Seco	Calif.	207 °F	1974
Robinson 2	S.C.	281 °F	1970
San Onofre 1	Calif.	229 °F	1967
Surry 1	Va.	200 °F	1972
TMI-1	Pa.	204 °F	1974
Turkey Point 3	Fla.	259 °F	1972
Turkey Point 4	Fla.	259 °F	1973
Yankee Rowe	Mass.	212 °F	1960

safety of PWR vessels," rather than what they actually were—a relaxation of the safety requirements.

In 1976, when responding to charges that the potential for reactor vessel rupture had serious safety implications, the NRC stated: "In-place annealing of reactor vessels has been demonstrated to be an effective means of restoring the material properties" (*Investigation of Charges Relating to Nuclear Reactor Safety,* Joint Committee on Atomic Energy, hearing record, 1192.). In contrast, the NRC's 1984 notice of its proposed rule contained the following factual statement: "Thermal annealing has never been attempted on a commercial reactor, let alone shown to be practical."

In July 1991, the Union of Concerned Scientists (UCS) and the New England Coalition on Nuclear Pollution (NECNP) took legal action against the NRC because the Yankee Rowe plant was operating in violation of the regulations on vessel embrittlement. At the time, the Yankee Rowe plant was the nuclear industry's leading candidate for an extension of its 40-year operating license—which may have accounted for the NRC's lack of enforcement of its regulations.

In 1990, the NRC had estimated that the reference temperature for the vessel's plates was 355 degrees Fahrenheit and the reference temperature for the circumferential welds was in the range of 330 to 370 degrees Fahrenheit, far above the limits of 270 degrees Fahrenheit and 300 degrees Fahrenheit, respectively. In addition, a consultant retained by the NRC estimated that the vessel's fracture toughness could be less than 30 foot-pounds, well below the 50 foot-pound limit.

The reason that the reference temperature and fracture toughness had to be estimated was that Yankee Rowe did not have samples of the vessel material that could be tested to measure the extent of embrittlement. The NRC was also aware that the reactor vessel had not been inspected for cracks even once during the 30 years the plant had been operating. Despite knowing that the plant was operating in violation of the NRC's own safety requirements, the NRC initially opposed the request by UCS and NECNP that the plant be shut down until it was in compliance with the regulations. The plant was closed in the fall of 1991, however, and never reopened. The utility claimed that the plant was safe to operate, but that it would cost too much to prove that hypothesis.

NRC's Current Assessment of Embrittlement

After embrittlement of the reactor vessel closed the Yankee Rowe plant for good, the NRC began to treat the embrittlement problem more seriously. In 1992, the NRC staff asked the utilities to determine whether pressurized water reactors and boiling water reactors would exceed vessel embrittlement limits prior to the expiration of their current operating licenses. The NRC's summary of those analyses was published in the report *Status of Reactor Pressure Vessel Issues* on October 28, 1994 (SECY-94-267).

The NRC concluded that for all except two of the plants, the reference temperatures of the reactor pressure vessels would remain below the 270 degrees Fahrenheit and 300 degrees Fahrenheit limits at the end of their *current* operating licenses. The Beaver Valley 1 plant in Pennsylvania and the Palisades plant in Michigan were predicted to exceed these limits in 2012 and 2004, respectively—before the expiration of their operating licenses in 2016 and 2007.

The NRC was unable to conclude that the fracture toughness of the vessel materials would remain above 50 foot-pounds throughout their operating life, citing "limitations in the available data" as the basis for being unable to reach a reliable conclusion. The NRC claimed that "generic" rather than plant-specific analyses had been performed, which supported a conclusion that all pressurized water reactors and boiling water reactors could have a fracture toughness of less than 50 foot-pounds and still have an adequate safety margin throughout their *current* operating licenses.

In the same report (SECY-94-267) to the NRC commissioners, however, the NRC staff hedged their conclusions on two counts. First, the memo cautions that "it is important to note that these results are based on the information currently reported by the licensees and are subject to change" and that "the assessment of RPV [reactor pressure vessel] integrity must be a continuing, proactive effort."

On May 8, 1995, the NRC issued an update to *Status of Reactor Pressure Vessel Issues* (SECY-95-119) based on new information that the NRC staff had obtained. In the fall of 1994, the owner of the Palisades plant had performed tests and chemistry analyses on the welds in its steam generators. The Palisades plant does not have irradiated samples of the vessel welds, and the owners substituted weld samples from the old steam generators that had been replaced. The owners claimed that the results of tests and analyses on the steam generator welds were applicable to the reactor pressure welds because the former were fabricated using the same procedures and weld material as those in the reactor vessel. The steam generator welds, however, were not exposed to neutron radiation received by the vessel welds.

Nevertheless, the tests and analyses indicated that the degree of embrittlement of the Palisades reactor pressure vessel could be higher than previously calculated. Tests determined that the copper and nickel concentration within the weld material varied greatly and that this variability could be three times greater than previous estimates. Using this new data, the NRC estimated that the vessel could exceed the allowable reference temperature in 1999 rather than 2004—five years earlier than the NRC had estimated only the year before.

A May 15, 1995, article in *Inside NRC* reported that William Russell, director of the NRC's Office of Nuclear Reactor Regulation, said that the chemical variability could substantially reduce the time before plants reach the reference temperature limits and that "there aren't going to be many reactors at all (with high copper content welds) that are going to make it" though an extended operating license period without heat treatment of the vessel. He also said that the number of plants that might not make it through the end of their currently licensed period could increase as well.

The same article reported that another NRC official identified nine plants that are potentially affected with shorter operating periods before reaching the reference temperature limits. The plants are Palisades in Michigan, Kewaunee in Wisconsin, Ginna in New York, Beaver Valley 1 in Pennsylvania, Point Beach 2 in Wisconsin, Turkey Point Units 3 and 4 in Florida, Robinson 2 in South Carolina, and Salem 2 in New Jersey.

The NRC reviewed other data previously withheld as "proprietary information" by the reactor vessel's manufacturer, Asea Brown Boveri/Combustion Engineering. The data indicated that the amount of embrittlement of the vessel welds in the Kewaunee plant in Wisconsin could be greater than previously calculated and that there was a large variability in the reported amount of copper and nickel in the welds.

The NRC staff informed the commissioners that the large variability observed in the chemical composition of the welds in the Palisades and Kewaunee reactor vessels could be applicable to other reactor pressure vessels and could significantly affect their embrittlement evaluations. The NRC also expressed concern that additional data not previously considered by the plant operators could affect the predicted time for reaching vessel embrittlement limits. Therefore, on May 19, 1995, the NRC required the owners of both pressurized water reactors and boiling water reactors to submit a written report providing any new data and assessing the impact of this data on vessel integrity. The NRC gave the utilities six months to submit their reports.

Dealing with Embrittlement

Officials have proposed a variety of means for dealing with the embrittlement of reactor pressure vessels; some have been implemented. One idea was to heat water stored in tanks that supply the emergency core cooling systems, in order to reduce the thermal shock to the reactor vessel in an accident. This technique is of limited value in reducing the probability of vessel rupture, however, and it reduces the effectiveness of the emergency core cooling systems.

One method used by many plants to slow the rate of vessel embrittlement is to redistribute the uranium in the reactor fuel. Reducing the concentration of uranium in the fuel assemblies at the periphery of the core reduces the radiation exposure to the vessel. In order to compensate for the lower power generation in the outer fuel assemblies, the power density in the center of the core must be increased if the plant's full power output is to be maintained. This decreases the safety margin against fuel melting in the event of an accident, however, because the center of the core operates at a higher temperature. In any event, this technique only slows the rate of vessel embrittlement; it does not stop it.

Heat Treatment of Reactor Vessels

In the years ahead, it appears likely that the nuclear industry and the NRC will promote heat treatment of the reactor vessel as a promising cure-all for embrittled reactor vessels. Thermal annealing of reactor pressure vessels, as this heat-treatment process is called, has never been attempted—let alone shown to be practical and effective—at a commercial US nuclear power plant, and a large number of practical and technical problems remain to be solved.

There are basically two potential ways to anneal a vessel in place. One is to use the reactor coolant pumps to heat the reactor cooling water above the normal operating temperature. This so-called wet annealing process would also heat the entire reactor cooling system, which is a major drawback: raising the temperature high enough to heat-treat the vessel could damage the reactor-cooling piping. In the other method, "dry" annealing, the fuel would be removed from the vessel, which would then be drained. Electrical heaters would be attached to the vessel and then be used to raise the temperature higher than could be safely used in a wet annealing process. The reactor vessel would have to be heated to the range of 800 to 900 degrees Fahrenheit and held at that temperature for about a week to achieve significant reversal of the effects of embrittlement.

The extent to which the reference temperature is reduced and the fracture toughness increased by the annealing process can be reliably determined only by destructive testing of samples of the vessel plates and welds before and after the heat treatment. If representative samples that have been exposed to the same radiation as the vessel are not available, the safety of continued operation will remain uncertain. The heating of the vessel must be uniform and applied for the correct length of time and at the correct heat-up and cool-down rate. Since only the vessel beltline will be heated, a difference of several hundred degrees could develop between the vessel wall and the lower head of the vessel. The resulting stress has the potential for causing crack growth after the plant resumes operation. Some evidence also exists that the vessel may reembrittle at a rate faster than its original embrittlement. Because reembrittlement is highly dependent on the material composition and the actual conditions used in annealing, it is necessary to have a reliable method for determining the condition of the vessel after annealing is completed and operation resumes.

In sum, although thermal annealing has the theoretical potential to restore some of the original properties of the reactor pressure vessel, its cost and effectiveness remain unknown.

Where to from Here?

Since embrittlement of reactor pressure vessels is an inevitable age-related hazard, more accurate, plant-specific data is essential if the NRC is to make a reliable judgment on the safety of continued plant operation. The NRC must cease its practice of either ignoring violations of the safety limits on vessel embrittlement or relaxing those requirements in order to allow continued operation of plants that become more dangerous the longer they operate.

State regulators are faced with the dilemma that they cannot rely on a utility's prediction of the time when the reactor will become too dangerous to continue operating without attempting an annealing process with uncertain effectiveness and unknown costs. When faced with the need to consider the prudence of some unrelated major expenditure by the utility, however, regulators would be wise to consider the potential for vessel embrittlement and the other age-related degradation mechanisms plaguing the nuclear industry. Regulators must set standards for deciding when further expenditures to repair an aging nuclear power plant are no longer in the best economic interests of electricity consumers.

Appendix

Commercial Pressurized Water Reactors Licensed for Operation As of 12/11/95

Alabama
Farley 1 & 2

Arkansas
Arkansas 1 & 2

Arizona
Palo Verde 1, 2 & 3

California
Diablo Canyon 1 & 2
San Onofre 2 & 3

Connecticut
Haddam Neck
Millstone 2 & 3

Florida
Crystal River 3
St. Lucie 1 & 2
Turkey Point 3 & 4

Georgia
Vogtle 1 & 2

Illinois
Braidwood 1 & 2
Byron 1 & 2
Zion 1 & 2

Kansas
Wolf Creek

Louisiana
Waterford 3

Maine
Maine Yankee

Maryland
Calvert Cliffs 1 & 2

Michigan
Cook 1 & 2
Palisades

Minnesota
Prairie Island 1 & 2

Missouri
Callaway

Nebraska
Fort Calhoun

New Hampshire
Seabrook

New Jersey
Salem 1 & 2

New York
Ginna
Indian Point 2 & 3

North Carolina
Harris
McGuire 1 & 2

Ohio
Davis-Besse

Pennsylvania
Beaver Valley 1 & 2
Three Mile Island 1

South Carolina
Catawba 1 & 2
Oconee 1, 2 & 3
Robinson 2
Summer

Tennessee
Sequoyah 1 & 2
Watts Bar 1

Texas
Comanche Peak 1 & 2
South Texas 1 & 2

Virginia
North Anna 1 & 2
Surry 1 & 2

Wisconsin
Kewaunee
Point Beach 1 & 2

US Nuclear Power Plants—Showing Their Age

Case Study: Steam Generator Corrosion

By Robert Pollard

Union of Concerned Scientists

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Robert Pollard is senior nuclear safety engineer for the Union of Concerned Scientists.

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Abstract

As more nuclear power plants approach middle age, it is becoming increasingly clear that a wide variety of degradation mechanisms pose significant economic and safety risks. The degradation of steam generators in pressurized water reactors (PWRs) is among the more perplexing problems confronting the nuclear power industry and its state and federal regulators. Since decades of effort have failed to control the problem, the US Nuclear Regulatory Commission should reconsider its practice of allowing PWRs to continue operating at full power with ever-increasing levels of steam generator degradation. State regulators should anticipate the inevitable costs of steam generator degradation and replace the current fix-or-replace-at-any-cost practice with a process for making cost-effective decisions before the steam generators become unfit for continued service.

This study focused on just one age-related problem and found that the nuclear industry and its regulators are not confronting the increasing risk of reactor accidents or the economic costs arising from the continuing degradation of PWR steam generators. Prudent officials at all levels of government need to adopt management plans based upon a recognition that there are limited options for meeting current and future challenges posed by steam generator degradation. It is simply not in the public interest to wait until a crisis develops to determine whether steam generator repair, steam generator replacement, or permanent plant shutdown is the preferable choice.

Introduction

Most complex technologies, nuclear and nonnuclear alike, experience technical problems and failures. With study and the application of new knowledge, however, these problems are typically corrected. Steam generator degradation in pressurized water reactors (PWRs) is an exception to this rule.

Thirty years ago nuclear technology was widely hailed as a panacea, a promising new source of electric power to satisfy the growing demands of an expanding, modern society. In reality, however, nuclear technology has actually created a host of tough new technical problems. Some of these problems—in particular, degradation of PWR steam generator tubes—have been unrelenting, and technical remedies remain out of reach despite many years of effort. To this day, the 73 PWRs (out of 110 licensed US nuclear power plants) are vulnerable to several forms of steam generator degradation.

Experience shows that tube degradation is inevitable with age and is manifested in a wide variety of forms, each requiring a unique solution. Over the years, as one form of tube degradation was brought under control, another appeared to take its place. This problem is continuing today, and it is growing worse rather than improving. Unfortunately, it is difficult to inspect and accurately assess damages to PWR steam generator tubes.

When plants were new, damaged tubes could be removed from service with little or no impact on the plant's maximum power output. But since the number of degraded tubes keeps increasing, plants are facing rising repair or replacement costs and lengthy, unscheduled outages—both of which threaten the economic viability of continued plant operation. In addition, new forms of corrosion raise the specter of bigger leaks and an increasing risk of reactor meltdown. Even more troublesome, undetected cracks in steam generator tubes pose an exceptionally high risk of radioactive contamination of the environment. In other words, PWRs pose a threat to both the health and the pocketbooks of millions of Americans.

For the sake of both economics and safety, federal regulators should acknowledge that the long search for a technical solution for aging steam generator tubes has failed. Indeed, with the appearance of new types of corrosion with unknown causes, the exceptionally high safety risk posed by aging steam generator tubes can be ignored no longer. It is time to defuse these nuclear time-bombs as quickly as possible.

The Nuclear Regulatory Commission (NRC) should cease its practice of relaxing the repair criteria for degraded steam generator tubes. This "let's-play-chicken" policy has increased the risk of nuclear accidents due to ruptured tubes. Since years of effort have not produced a way to stop tube degradation, continued federal relaxation of the tube repair criteria is not a defensible public policy.

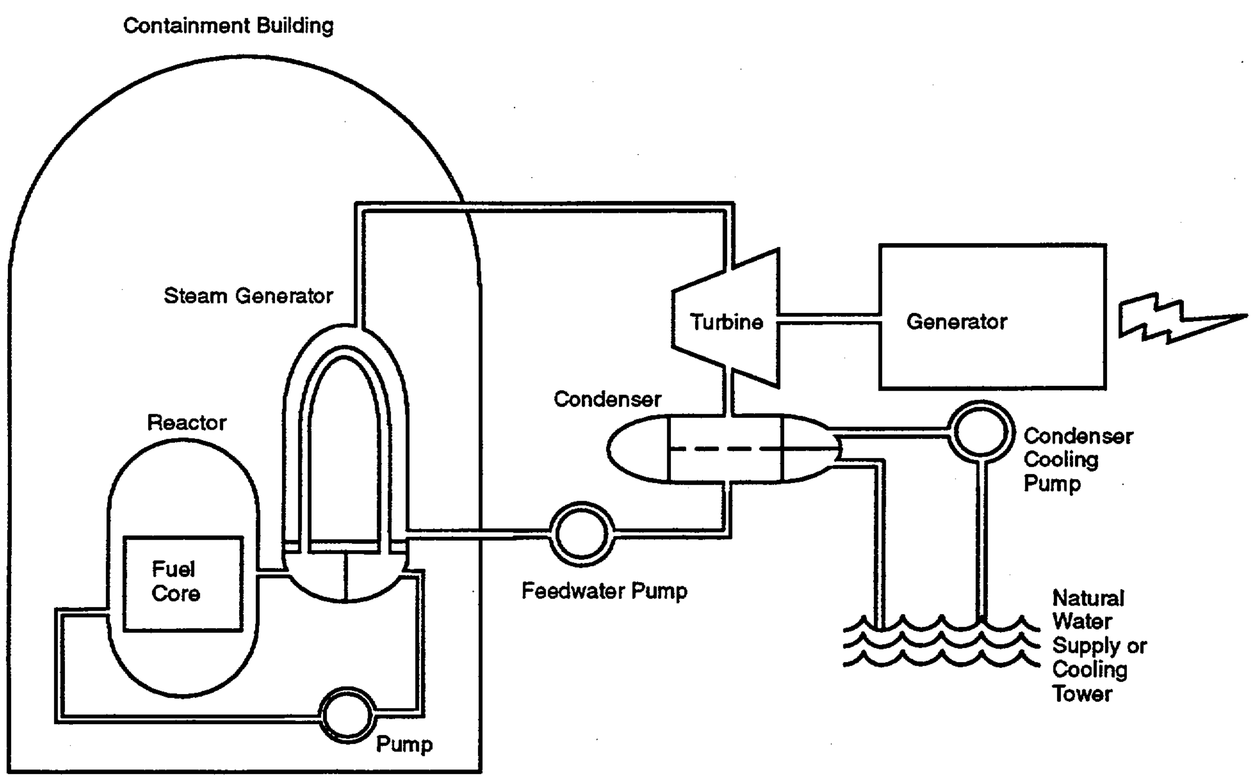
State regulators, on the other hand, must develop a strategy for dealing with the inevitable—increasingly more frequent, unscheduled shutdowns of PWR plants in the years to come, and the need to promulgate standards for deciding between early plant decommissioning or steam generator replacement.

How a PWR Nuclear Power Plant Works

Figure 1 is a simplified diagram of a nuclear plant utilizing a pressurized water reactor. There are three principal cooling water circuits: the primary reactor cooling system; the secondary steam, condensate, and feedwater systems; and the condenser cooling system.

Figure 1

PRESSURIZED WATER REACTOR PLANT



The primary cooling system contains water pressurized to about 2,200 pounds per square inch (psi), which is pumped through the reactor, where it is heated to an average temperature of about 550 degrees Fahrenheit. This hot water, contaminated with radioactive material, then flows through the metal tubes of the steam generator. Heat conducted through the tube walls boils a secondary water supply surrounding the outside of the tubes. The primary reactor coolant is then pumped back to the reactor to be reheated.

The secondary system operates at a much lower pressure than the primary system, producing steam at a pressure of about 1,000 psi, which is used to drive the plant's turbine-generator. Steam exhaust from the turbine enters the condenser, where it is cooled to liquid condensate, which is then pumped back to the steam generators as feedwater.

The condenser cooling system pumps water from a natural body of water or a cooling tower through tubes in the condenser, and the water flows back to its source. About two-thirds of the energy produced by the reactor is released to the environment by the condenser cooling system, and only one-third is converted into electricity in the turbine-generator.

PWR Steam Generators

Figure 2 illustrates a typical steam generator used in PWR plants. A steam generator weighs a few hundred tons and is taller than the reactor itself. Each plant has from two to four steam generators, depending on the plant's size and design. Each steam generator contains 3,000 to 15,000 tubes, each about 70 feet long and three-quarters to seven-eighths of an inch in diameter and with a wall thickness of one-twentieth of an inch. The thin tube walls form the only barrier separating the radioactive water in the primary reactor cooling system from the "clean" water in the secondary steam, condensate, and feedwater systems.

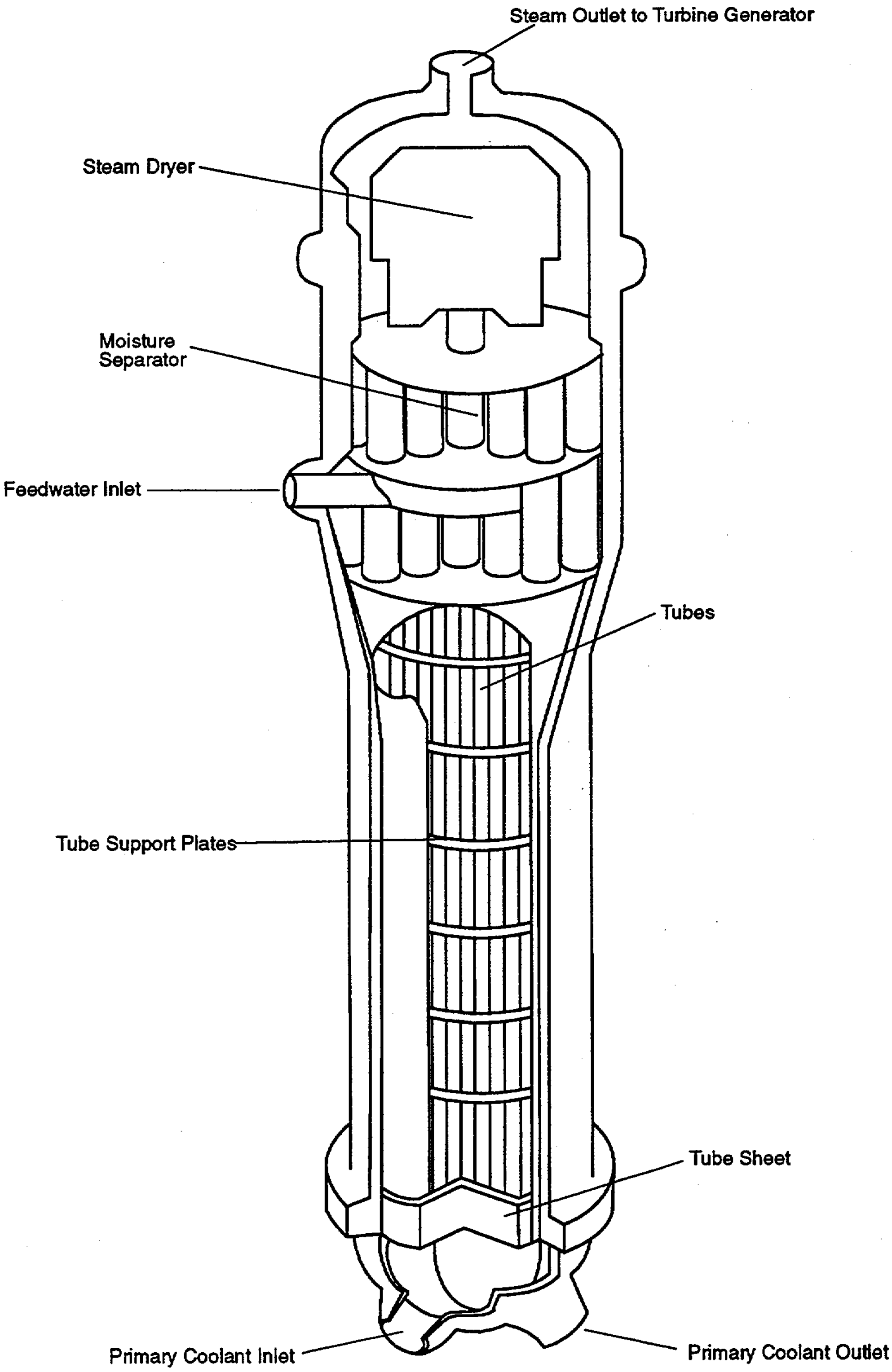
Safety Hazards of Steam Generator Leaks

Although the reactor, the primary cooling system, and the steam generators are located within a containment building, the secondary steam, condensate, and feedwater systems are located outside. Because the reactor operates at a much higher pressure than the steam system, any leaks or ruptures in the steam generator tubes allow the radioactive water to escape into the secondary systems and then into the environment.

The most serious safety hazard is the simultaneous rupture of several cracked tubes—a situation that could lead to a meltdown accident. The reactor's emergency core cooling systems (ECCS) were designed on the questionable assumption that the worst accident involving steam generator tubes would be the rupture of one tube in one steam generator. The probability of multiple tube ruptures was viewed as so low that the ECCS were not designed for that possibility.

Figure 2

TYPICAL PWR STEAM GENERATOR



The continuing corrosion of steam generator tubes, however, and the unreliable methods of detecting the corrosion have resulted in plants operating with an unknown number of cracked tubes. This is exactly the situation described by NRC Commissioner Kenneth C. Rogers in an August 30, 1988, speech to the International Symposium on Nuclear Power Plant Aging:

> The concern is not a single tube leaking or even failing. The concern is with sudden multiple tube failures—common mode failures. For example, such failures could come about by having essentially uniform degradation of the tubes. Degradation would decrease the safety margins so that, in essence, we have a "loaded gun," an accident waiting to happen. Under those conditions, a pressure transient or a seismic event could rupture many tubes simultaneously. That could allow primary coolant to enter the secondary system and the resulting high pressure to lift the relief valves that are outside containment on the steam line, thus permitting primary water to bypass containment and communicate with the atmosphere directly, resulting in a LOCA [loss-of-coolant accident].

Because reactor pressure is more than 1,000 psi higher than the steam system pressure, the rupture of one tube results in the loss of reactor-cooling water at an initial rate of about 600 to 700 gallons per minute. If several tubes rupture, the pressure on the secondary side of the steam generators rises rapidly, opening the steam generator pressure-relief valves, which discharge directly into the atmosphere outside the containment building. The loss of so much water could render the ECCS ineffective. The subsequent melting of the reactor fuel would release the intensely radioactive fission products, which could then escape through the broken tubes and out the steam generator relief valves into the environment.

Even small leaks through the steam generator tubes can have safety and economic consequences. Radioactive gases carried with the steam to the condenser are discharged into the atmosphere by the condenser air ejector, increasing the radiation dose to the public. In addition, tube leaks can contaminate the secondary systems, increasing both the radiation exposure to plant workers and the costs of repairing and maintaining those systems.

Degradation in PWR Steam Generators

Figure 3 illustrates some of the internal components and the locations of tube degradation in steam generators used in PWRs designed by Westinghouse and Combustion Engineering. The seven PWRs designed by Babcock & Wilcox use steam generators of a different design, but these reactors, too, have experienced similar types of degradation.

The tubes are made of Inconel 600, an alloy developed by the International Nickel Company that consists primarily of nickel, chromium, and iron. Tubes in the shape of an inverted "U" are anchored in a "tube sheet," about two feet thick, near the bottom of the steam generator. During steam generator fabrication, the tubes are mechanically "rolled" or otherwise expanded firmly against the tube sheet holes and then welded on the bottom face of the tube sheet. The expansion process leaves internal stresses within the tube wall that have proven to be the site of stress corrosion cracking, initiated on both the inside and outside of the tube. Residual stress from forming the U-bend in the tubes and the antivibration bars at the U-bend region of the tubes have also been the site of stress corrosion cracking and "fretting," or wear of the tube walls.

Several tube support plates, about three-quarters of an inch thick, are used along the length of the tubes to maintain the spacing between the long slender tubes. The section of the tubes where they pass through the tube support plates has been the site of tube wall thinning and tube denting. Corrosion products building up in the space between the tube and the tube support plate dent the tube and increase its susceptibility to stress corrosion cracking.

One form of degradation that is becoming more prevalent is circumferential cracking of the tubes in the so-called freespan lengths of tubes between the tube support plates (earlier forms of degradation resulted in cracking along the length of the tubes). Cracks around the tube circumference increase the chance of a tube pulling apart, allowing reactor coolant to escape from both ends of the rupture. Such circumferential cracking caused the two most recent tube ruptures, at McGuire Unit 1 in North Carolina (a Westinghouse PWR) and the Palo Verde Unit 2 plant in Arizona (a Combustion Engineering PWR). The NRC has stated that "experience shows that tubes with circumferential cracking may become vulnerable to rupture without significant precursor leakage."

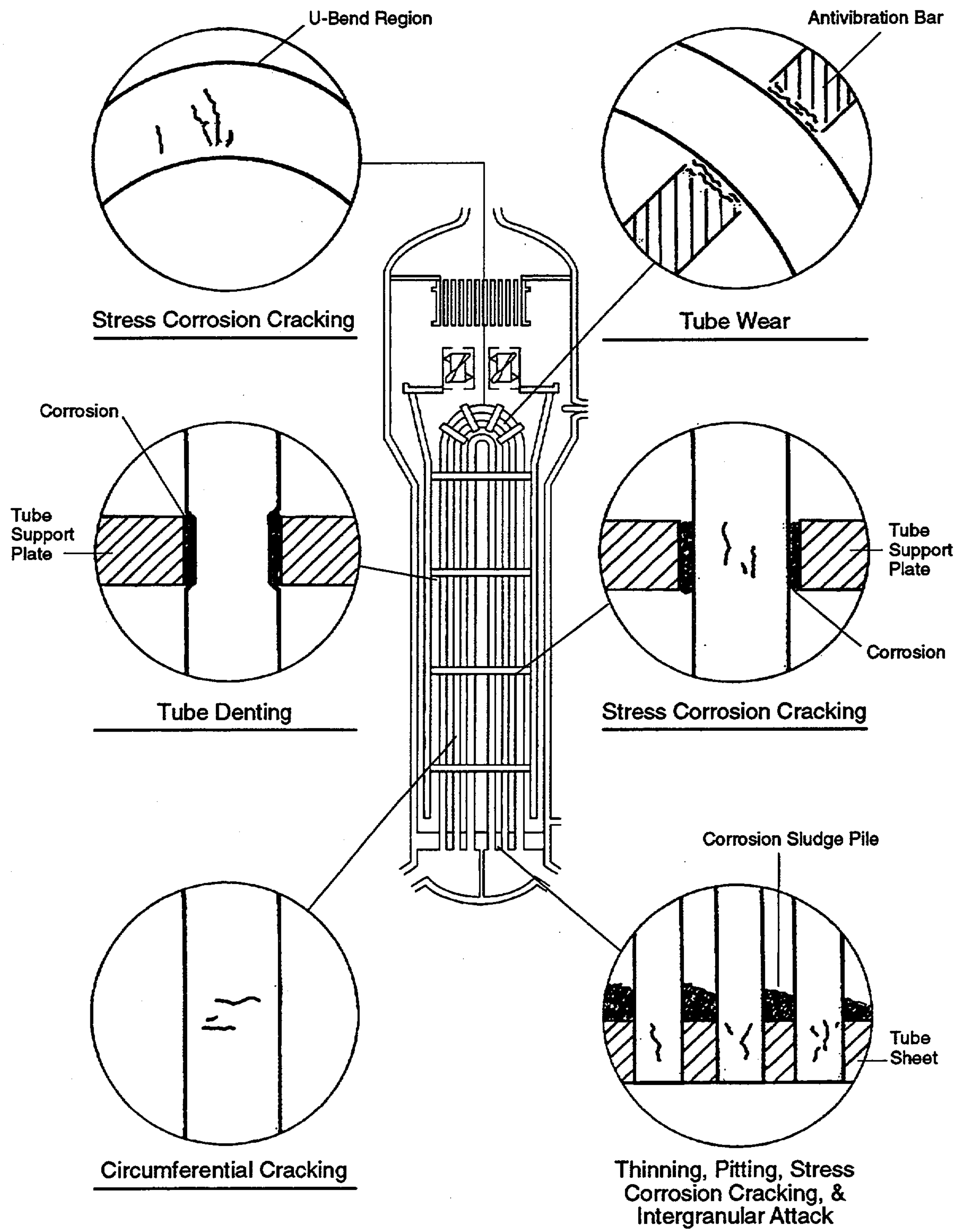
Currently, the intergranular attack and stress corrosion cracking that began appearing in the late 1970s are the most prevalent types of degradation affecting steam generators. Such corrosion tends to follow the grain boundaries in the metal. Intergranular attack is characterized by uniform degradation of the grain boundaries at the surface and occurs if the metal is not under significant stress. If the metal is subject to higher stresses from construction methods or operating conditions, the cracks penetrate into the metal along the grain boundaries. To date, no method has been identified to stop this type of corrosion in existing steam generators, and it threatens to limit the remaining life of several plants unless steam generator replacement is an economical option.

Past Attempts to Halt Steam Generator Degradation

As early as the 1970s, the seesaw campaign to understand the causes of and develop remedies for steam generator degradation processes was well established. With the rise of each new steam generator problem (see figure 4), the nuclear industry reacted by forming a study group to find a technical fix. Early on the method appeared to work, and the problems plaguing steam generators in the 1970s were virtually eliminated. But the efforts proved less than successful as earlier "solutions" actually caused additional problems and new forms of steam generator degradation kept appearing.

Figure 3

CORROSION LOCATIONS



In the 1970s, for example, sodium phosphates were used in the secondary feedwater to control acidity and corrosion in the steam generators. The phosphates concentrated in crevices, however, and actually led to corrosion and a generalized thinning referred to as wastage. By the mid-1970s, some steam generators—which are supposed to last for the 40-year life of a plant—had deteriorated to the point that they had to be replaced after less than 10 years of operation.

The strategy then changed to using all volatile chemicals, such as ammonia, in highly purified secondary water. The change in chemistry, however, led to rapid corrosion of the tube support plates that were fabricated from carbon steel. The buildup of corrosion products in tube support plate holes caused pinching or denting of the tubes, which created metal stress that increased corrosion rates.

In the 1980s, the extensive use of copper in secondary system components was believed to be responsible for pitting on the outside of the tubes. In addition, leaks in condenser tubes allowed impurities to enter the secondary water; these impurities then concentrated in the steam generators. The corrosion products from the secondary systems and within the steam generator built up as a sludge pile on the tube sheet covering the outside of the tubes and contributed to pitting on the tubes. To eliminate some of the sources of copper and condenser impurities, condensers and other heat exchangers in secondary systems of some plants were replaced with tubes of other materials, such as stainless steel or titanium, although sometimes this was done only in conjunction with replacement of the steam generators.

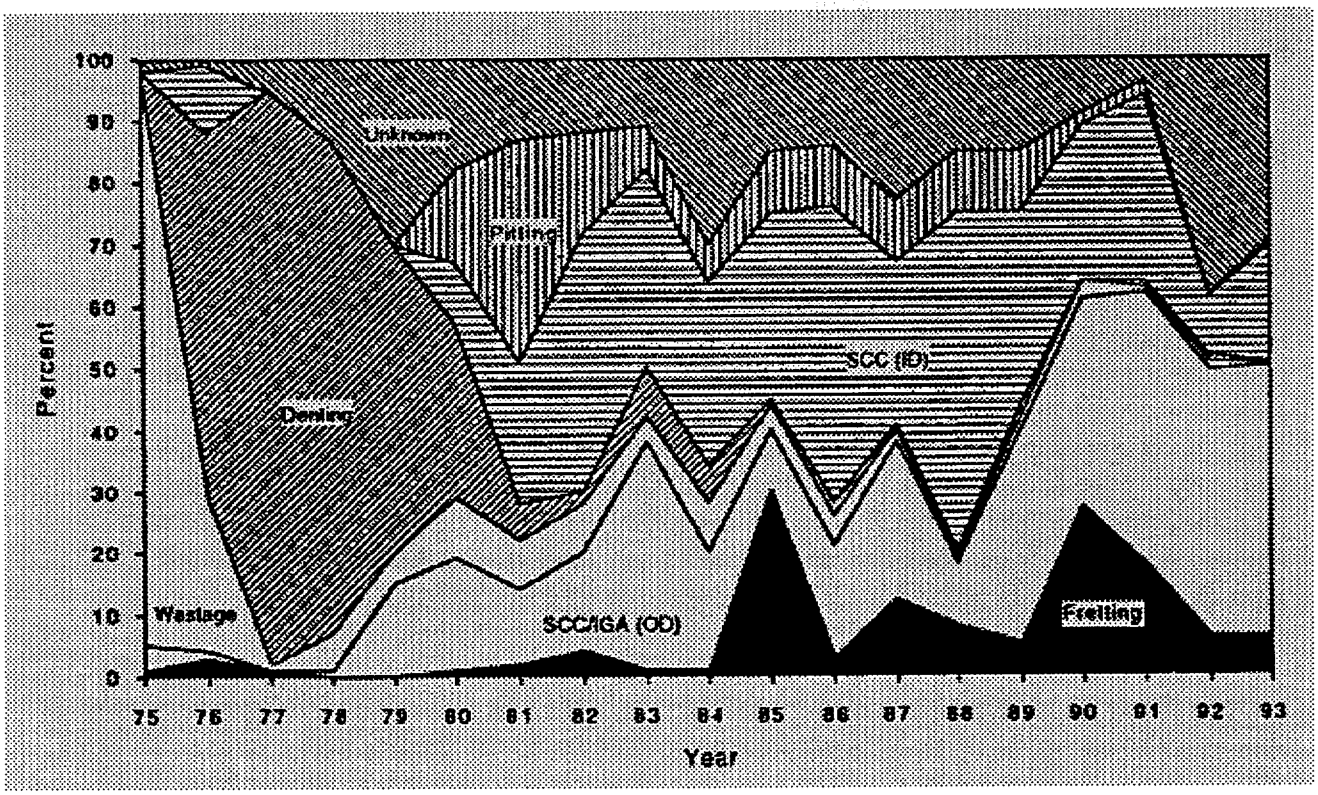
An important aspect of the data in figure 4 is the continued prevalence of "unknown" as the cause of steam generator corrosion. From the late 1970s through the 1980s, 10 to 20 percent of the tube degradation resulted from unknown causes. The NRC reports that in recent years, 30 to 40 percent of the tube degradation has resulted from unknown causes. After two decades of attempting to understand and correct the causes of steam generator tube degradation, it is time to acknowledge that this aging problem is out of control and is likely to continue to worsen in the future.

Detecting Steam Generator Tube Degradation

The NRC is well aware of the unreliability of the methods used to detect degradation of the steam generator tubes. In a May 26, 1993, internal staff report (Operating Reactors Events Briefing 93-19), the NRC reported that "there have been widespread deficiencies in [steam generator] inspection programs throughout the industry." The NRC concluded that cracks penetrating 40 percent through the tube wall "cannot be reliably detected." This was an important finding, because the NRC's safety standard requires that a tube be repaired or removed from service if cracks 40 percent through the tube wall are detected. Significantly, then, the nuclear industry cannot even determine whether it meets this NRC safety standard.

Figure 4

CHANGES IN TUBE DEGRADATION TYPE OVER TIME



SCC/IGA (OD): stress corrosion cracking/intergranular attack (outside diameter)

SCC (ID): stress corrosion cracking (inside diameter)

The steam generator tubes can only be inspected for corrosion and cracks when the plant is shut down. Thus, the rate at which the tubes are corroding is unknown during the 12 to 24 months between scheduled shutdowns for reactor refueling. Furthermore, the NRC does not require that all tubes be inspected for their entire length during each inspection. Even when the tubes are inspected, a number of uncertainties remain.

The standard tube inspection method is called eddy current testing. An electrical probe is passed through the tube, and an alternating current applied to the probe induces a secondary, or "eddy," current in the tube wall. The amount and configuration of the metal surrounding the probe influence the electrical signals that are detected. If correctly interpreted, the signals can indicate the location of cracking or other degradation of the tubes, but the type of degradation and the length and depth of any cracking are difficult to determine. For example, different forms of corrosion produce similar signals in the eddy current probe. Thus, the relationship between the voltage signal from the eddy current probe and the actual physical condition of the tube is uncertain.

Another source of uncertainty derives from the fact that other parts of the steam generators affect the eddy current signal. If, for example, the tubes are cracked or degraded in locations where other metal components, such as the tube support plates, are close to the tube walls, the tube cracks can be masked by the metal outside the tube.

If analysis of the data from eddy current inspections does not disclose tube degradation before tube integrity is impaired, leaks of reactor cooling water into the secondary systems might be detected by an increase in radiation before a tube rupture accident occurs. Some plants have installed radiation detectors on the main steam pipes that carry steam from the steam generators to the turbine-generator. These detectors give the reactor operator a prompt indication of a steam generator tube leak and also identify the leaking steam generator. This may give the reactor operators sufficient time to shut down the plant before a small tube leak turns into a tube rupture accident. Some plants do not have such detectors, however, because the NRC has not required their installation. For these plants, detection of steam generator leaks is delayed, and the leak rate is generally higher before it is detected. The NRC-allowed rate of leakage through steam generator tubes varies from plant to plant, depending primarily on whether the NRC has allowed continued plant operation despite the existence of cracks more than 40 percent through the tube walls. Allowable leak rates range from a few gallons per minute to about one-tenth of a gallon per minute.

The lower allowable leak rate is imposed on plants that have received NRC permission to continue operating despite the presence of deep tube cracks. For many years, utilities generally accepted the NRC's requirement that tubes with cracks deeper than 40 percent of the tube wall had to be repaired or removed from service. As steam generator degradation continued to worsen, however, the number of tubes requiring repair or removal threatened to reduce the power output of the plant or to require either replacement of the steam generators or early permanent closure of the plant. The utilities argued that the 40 percent through-wall standard was too conservative. The NRC responded by approving the use of a repair criterion based on voltage signals from the eddy current inspections. Tubes that would have had to be repaired under the depth-based criterion are allowed to remain in service, unrepaired, under the voltage-based criterion. In an attempt to compensate for the increased risk posed by operation with deep cracks, the allowable leak rate during normal operation is reduced. Under accident conditions, however, the tubes with deeper cracks are more likely to fail.

Steam Generator Repair Options

With detection of degradation more severe than the NRC permits, only two alternatives are available for repairing steam generator tubes. A tube can either be removed from service by plugging both ends, or a metal sleeve can be inserted inside the tube and welded in place, bridging the defective area of the tube. The only other course of action is to replace the steam generators or decommission the plant.

Plugging of tubes reduces the heat transfer area in the steam generators, lowers the flow rate in the reactor cooling water system, and costs a few hundred dollars per tube. Sleeving, on the other hand, has little effect on the heat transfer capability of the steam generators and, compared to plugging, has a smaller effect on reactor coolant flow rate. About 10 to 20 tubes can be sleeved before the reduction in reactor cooling flow is equal to that caused by plugging one tube. At a cost several thousand dollars per sleeve, however, it is much more expensive, and, unlike plugging, sleeving is not a permanent repair. Both the welding itself and the process of expanding the sleeve against the original tube wall create stresses within the weld and tube wall that result in continuing corrosion. The installed sleeve also prevents installation of another sleeve if tube degradation occurs at another location above the sleeve. Finally, since sleeving reduces the tube's inside diameter, a smaller eddy current probe must be used, which complicates interpretation of the eddy current signal.

The reductions in steam generator heat transfer area and reactor cooling water flow have several effects. If the maximum power output of the plant is to remain the same, the temperature of the water leaving the reactor and entering the steam generator must be increased in order to transfer the same amount of heat to the secondary system. This, in turn, means that the reactor fuel temperature must be increased, reducing the safety margin to fuel melting in the event of an accident. The increased temperature also accelerates corrosion in the tubes remaining in service. On the other hand, if the reactor temperature is reduced in an attempt to slow further steam generator degradation, the rate of radiation embrittlement of the reactor vessel increases, and the plant's power output decreases.

Some tubes can be plugged or sleeved without reducing the plant's power output. Aside from the economic considerations, however, the number of tubes that can be plugged and sleeved is also limited by safety considerations. PWRs are required to be designed to withstand a break of any pipe in the reactor cooling system. In a such a so-called loss-of-coolant accident, the hot pressurized water gushes out of the reactor, and some of the water is assumed to flow through the steam generator tubes to the location of the pipe break. If too many tubes are plugged or sleeved, the escaping water will meet more resistance, and the pressure in the reactor will not be reduced as quickly. This will delay water from the emergency core cooling system reaching the reactor core. A delay of even a few seconds can result in the core reaching a much higher temperature. Thus, a plant-specific analysis of the design basis loss-of-coolant accident is needed to determine how many steam generator tubes can be sleeved or plugged.

Typically, once a PWR reaches its plugging limit, the utility claims that the original analysis of emergency core cooling capability was overly conservative, and the NRC increases the plugging limit. In some cases, a plant's plugging limit has been increased more than once. Although the NRC claims that the revised analyses still meet the safety criteria, there can be no dispute that the safety margin for coping with loss-of-coolant accidents has been much reduced by the degradation and subsequent plugging and sleeving of steam generator tubes.

Economic Impact of Steam Generator Degradation

Both the history of steam generator degradation and the future implications of continuing tube corrosion paint a bleak economic picture. Two decades of trial-and-error attempts to control steam generator degradation have been ineffective and costly.

The problems are not unique to US plants; they affect PWRs worldwide. In June 1992, an NRC team visited France, Sweden, and the United Kingdom and attended an international meeting on steam generator problems. In its official trip report dated November 10, 1992—which the NRC intended to withhold from the public but which UCS obtained—the NRC reported that

- there is general acceptance around the world that steam generator tube ruptures are unavoidable given the inherent limitations of the alloy used and the shortcomings of the tube inspection techniques;
- the United States lags behind major European countries in terms of the scope of steam generator tube inspection programs;
- the maximum tube leak rate allowed during normal operation is much lower in European countries than the NRC permits in US PWRs; and
- much broader use of radiation detectors on steam lines to detect tube leaks occurs in Europe than in the United States.

The following year, in a May 26, 1993, "Operating Reactors Events Briefing," the NRC summarized the experience with PWR steam generators in the United States: "Steam generator tube degradation problems are widespread throughout the industry." As support, the NRC cited

- seven steam generator tube rupture "events" (accidents);
- numerous forced plant shutdowns;
- extensive tube repairs and extensions of scheduled shutdowns;
- steam generator replacements at 11 plants, an average of one plant per year between 1980 and 1993; and
- significant radiation exposure to workers.

With an eye toward the future, the NRC compiled a list of recent trends of concern, with stress corrosion cracking appearing as the dominant mechanism affecting steam generators and circumferential cracking becoming more prevalent. The NRC concluded that "there is no end in sight to these problems for plants operating with their original steam generators."

The NRC's gloomy outlook did not improve with the passage of time. At the May 9–10, 1995, Regulatory Information Conference, the NRC reported again on the trends in steam generator degradation: forms of degradation have changed; older US steam generators are experiencing an increasing amount of degradation; and degradation of previously sleeved tubes may be an emerging problem. The NRC's assessment of the economic implications for the nuclear industry was for more of the same: increased forced outages; increased plugging, sleeving, and associated costs; a potential for power reductions as steam generator plugging increases; and shortened operating life of steam generators, with continued plant viability becoming a major concern.

The NRC also assessed the regulatory implications of this situation, reporting that the NRC staff was regulating on an ad hoc basis in an "unstable regulatory environment"—a result of the drain on NRC staff resources caused by increasing requests for license amendments to relax the tube repair criteria. This situation is destined to prevail in the future, since the industry has estimated that up to 30 proposals for different tube repair standards will be submitted to the NRC for approval within the next one to two years.

In its public pronouncements, the nuclear industry portrays a more optimistic outlook but acknowledges the continuing nature of steam generator degradation. An article in the May/June 1995 issue of the Electric Power Research Institute's *EPRI Journal,* "Solutions for Steam Generators," describes improvements in the materials and design of replacement steam generators, which have so far had experienced less degradation. For plants operating with their original steam generators, however, EPRI reports that some degradation mechanisms have not yet been controlled and thus threaten to limit the useful life of many steam generators.

Replacing a plant's steam generators costs about $100 million to $200 million, plus the cost of replacement power while the plant is out of service. With experience, the time needed to replace steam generators has been reduced, thus decreasing the cost of buying replacement electrical power. It also appears, so far, that changes in design (to eliminate areas of low flow where corrosion products are deposited as sludge) and use of a different alloy and new heat treatment processes during fabrication of the tubes have reduced the rate of tube degradation in replacement steam generators.

Looking Toward the Future

After two decades of effort, the nuclear industry and the NRC should confront the fact that the hunt for a technical remedy to steam generator degradation has failed. The NRC should cease its policy of relaxing repair standards in order to allow plant operation to continue despite an increasing number of degraded tubes with deeper cracks. This policy provides no safety benefit to the public. On the contrary, it only increases the risk of a major reactor accident.

State regulators should recognize that since the number of degraded tubes and the severity of the tube degradation continue to increase, it is only a matter of time until a crisis develops. The nuclear industry faces increasing plant outages, rising repair costs, reduced power output, and either replacement of the steam generators or permanent closure of affected plants. State regulators should develop and promulgate standards for deciding which option is in the best interest of the ratepayers. It is not necessary to wait until steam generator degradation forces an unscheduled plant outage to determine whether extensive steam generator repairs and steam generator replacements are viable economic options. In fact, delaying a decision on steam generator replacement not only makes an accident more likely, but it also makes it more likely that replacement will not be economically viable because of the shorter time remaining until the plant's operating license expires.

Appendix

Commercial Pressurized Water Reactors Licensed for Operation As of 12/11/95

Alabama
Farley 1 & 2

Arkansas
Arkansas 1 & 2

Arizona
Palo Verde 1, 2 & 3

California
Diablo Canyon 1 & 2
San Onofre 2 & 3

Connecticut
Haddam Neck
Millstone 2 & 3

Florida
Crystal River 3
St. Lucie 1 & 2
Turkey Point 3 & 4

Georgia
Vogtle 1 & 2

Illinois
Braidwood 1 & 2
Byron 1 & 2
Zion 1 & 2

Kansas
Wolf Creek

Louisiana
Waterford 3

Maine
Maine Yankee

Maryland
Calvert Cliffs 1 & 2

Michigan
Cook 1 & 2
Palisades

Minnesota
Prairie Island 1 & 2

Missouri
Callaway

Nebraska
Fort Calhoun

New Hampshire
Seabrook

New Jersey
Salem 1 & 2

New York
Ginna
Indian Point 2 & 3

North Carolina
Harris
McGuire 1 & 2

Ohio
Davis-Besse

Pennsylvania
Beaver Valley 1 & 2
Three Mile Island 1

South Carolina
Catawba 1 & 2
Oconee 1, 2 & 3
Robinson 2
Summer

Tennessee
Sequoyah 1 & 2
Watts Bar 1

Texas
Comanche Peak 1 & 2
South Texas 1 & 2

Virginia
North Anna 1 & 2
Surry 1 & 2

Wisconsin
Kewaunee
Point Beach 1 & 2