Erosion in elbows in hydrocarbon production systems: Review document

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Erosion in elbows in hydrocarbon production systems: Review document

Mr N A Barton
TÜV NEL Limited
Scottish Enterprise Technology Park
East Kilbride
Glasgow
G75 0QU

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An overview is given of different erosion mechanisms and the factors that influence them. As sand erosion is the primary cause of problems in oil and gas production facilities, the report then goes on to look at particulate erosion in more detail, particularly focusing on elbows. A section is included on methods used to minimise, control and predict erosion in production systems. Conclusions are then drawn based on the review.

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EXECUTIVE SUMMARY

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1. INTRODUCTION

This report provides an overview of erosion mechanisms in elbows in oil and gas production systems. It forms part of a study that has been performed by the National Engineering Laboratory on behalf of the Health and Safety Executive into a specific erosion failure related incident.

Erosion is a complex process that is affected by numerous factors and small or subtle changes in operational conditions can significantly affect the damage it causes. This can lead to the scenario in which high erosion rates occur in one production system, but very little erosion occurs in other seemingly very similar systems. Detection of erosion as it progresses is also difficult and plant operators rarely have a good measure of the internal condition of the pipework in their systems. This makes erosion management difficult, especially for those unfamiliar with the manner in which erosion occurs.

Erosion has been long recognised as a potential source of problems in oil and gas production systems. A number of dangerous elbow failures occurred in UK waters on production platforms and drilling units between 1993 and 2001 (see Appendix I). The inherently variable nature of the erosion process makes it very difficult to develop definitive best practice recommendations that will apply to all elbows in hydrocarbon production systems. Rather than attempting to do this, this document provides an overview of the subject and guidance that will help Engineers to make more informed judgements on management of erosion in the particular hydrocarbon systems they operate.

Section 2 describes different erosion mechanisms and discusses the factors that influence erosion. Subsequent sections concentrate on the particle erosion process, as it is more likely to be an issue in production and drilling systems than other erosion mechanisms.

Section 3 describes the erosion of elbows in more detail. The purpose of this section is to give a more comprehensive understanding of the particle erosion process in particular scenarios.

Section 4 identifies different techniques used to manage particulate erosion. Measures used to avoid or minimise erosion are summarised. A number of prediction methods are then described in detail and their results are compared to highlight difficulties inherent in erosion estimation.

Section 5 summarises and draws conclusions from the review and gives recommendations on limiting erosion in elbows in oil and gas production systems.

2. THE EROSION PROCESS IN ELBOWS IN HYDROCARBON PRODUCTION SYSTEMS

Hydrocarbon wells produce a complex multiphase mixture of components including-

- Hydrocarbon liquids – oil, condensate, bitumen
- Hydrocarbon solids – waxes, hydrates
- Hydrocarbon gases (natural gas)
- Other gases – hydrogen sulphide, carbon dioxide, nitrogen
- Water with dilute salts
- Sand and proppant particles

There is not a large amount of published data on erosion problems in the field. Previous experience at NEL suggests that this is because operating companies are reluctant to publicise their problems and that erosion may be more common than published data implies. Another reason for this may be that the sporadic nature and complexity of erosion problems makes it difficult to draw conclusions from statistically-based field studies.

Potential mechanisms that could cause significant erosion damage are:

- Particulate erosion
- Liquid droplet erosion
- Erosion-corrosion
- Cavitation

It is generally accepted that particulates (sand and proppant) are the most common source of erosion problems in hydrocarbon systems. However, all of the other mechanisms are equally aggressive under the right conditions.

This section gives an overview of erosion of elbows in hydrocarbon production systems, identifying which components are most likely to be affected and how material properties influence erosion in these components. The different erosion mechanisms are then described.

2.1 Vulnerability of Components

Venkatesh[1] provides a good overview of erosion damage in oil wells. Regardless of the erosion mechanism, the most vulnerable parts of production systems tend to be components in which:

- the flow direction changes suddenly
- high flow velocities occur caused by high volumetric flowrates
- high flow velocities occur caused by flow restrictions

Components and pipework upstream of the primary separators carry multiphase mixtures of gas, liquid and particulates and are consequently more likely to suffer from particulate erosion, erosion-corrosion and droplet erosion.

The vulnerability of particular components to erosion heavily depends on their design and operational conditions. However, the following list is suggested as a rough guide to identify which components are most vulnerable to erosion (the first on the list being most likely to erode):

- Chokes
- Sudden constrictions
- Partially closed valves, check valves and valves that are not full bore
- Standard radius elbows
- Weld intrusions and pipe bore mismatches at flanges
- Reducers
- Long radius elbows, mitre elbows
- Blind tees
- Straight pipes

The erosive behaviour of elbows and blind tees is further discussed in Section 3.

2.2 Material Properties

Material properties have a significant effect on erosion and, in general, a material that is resistant to one type of erosion will be resistant to others. In oil and gas production systems nearly all components will be made of ductile metals; predominantly steels. Plastics, rubbers, elastomers, composites and similar materials may also be present. If erosion problems are suspected specialist erosion-resistant materials such as tungsten carbide may also be used. This section gives a brief summary of how different materials behave in an erosive environment.

2.2.1 Ductile Metals and other Common Materials

Steels, other metals and most plastics generally show ductile erosive properties. Particulate erosion in ductile materials erosion is primarily caused by a process known as micro-machining. In this process particles impacting at an angle to the surface scoop away material. At high impact angles, particle impacts on ductile surfaces tend to generate craters, but they do not remove as much material. The relationship between material properties and droplet impingement and cavitation erosion mechanisms are less well understood.

The primary factor controlling erosion in ductile materials is the material hardness. Consequently steels are more resistant than softer metals. Different steels have different hardness values. However, there is some debate as to whether this variation is sufficient to cause much variation in erosion resistance. Haugen at al[2] suggest that the difference between different grades of steel is negligible for impact velocities of less than 100 m/s.

Plastics and composites are generally less resistant than metals, although rubber and some polymers are quite resistant to particulate erosion because they absorb the energy of impacting particles.

2.2.2 Specialist Erosion-Resistant Materials

Specialist materials such as tungsten carbides, coatings and ceramics are often used in chokes and highly vulnerable components. These materials are generally hard and brittle.

Brittle materials erode in a different manner. Impacts on brittle materials fracture the surface and erosion increases linearly with impact angle, being a maximum for perpendicular impacts. This will affect the shape of the erosion scar and the position of maximum wear.

Most of these materials have a superior erosion resistance to steel (often orders of magnitude better). However, some coated materials are vulnerable to erosion. Initially they may show a high resistance, but once the coating, or it's substrate fails, their resistance may rapidly reduce.

2.3 Sand and Particulate Erosion

Particulate erosion mechanisms have been extensively studied and there has been some success in predicting particulate erosion rates. These prediction methods will be discussed in section 4.

Important factors determining the rate of particle erosion are:

- The flowrate of sand and the manner in which it is transported through the pipework
- The velocity, viscosity and density of the fluid through the component
- The size, shape and hardness of the particles

These factors will be considered in turn:

2.3.1 Sand Production and Transport

The nature of the sand and the way in which it is produced and transported also determines the rate of erosion within a production system. The sand production rate of a well is determined by a complex combination of geological factors, and can be estimated by various techniques, for example those described by Marchino[3]. Often, new wells produce a large amount of sand and proppant as they "clean up". Typically sand production then stabilises at a relatively low level before increasing again as the well ages and the reservoir formation deteriorates. Sand production is typically erratic[4] and sand concentration typically ranges from 1 to 50 parts per million by mass upstream of the first stage separators. If a well produces less than 5 to 10 lb/day (2.1×10^{-5} to 5.2×10^{-5} kg/s) it is often regarded as being sand-free[5]. However, this does not eliminate the possibility that erosion may be taking place.

The sand transport mechanism is an important aspect controlling erosion within productions systems. Gas systems generally run at high velocities (>10 m/s) making them more prone to erosion than liquid systems. However, in wet gas systems sand particles can be trapped and carried in the liquid phase. Slugging in particular can generate periodically high velocities that may significantly enhance the erosion rate. If the flow is unsteady or operational conditions change, sand may accumulate at times of low flow, only to be flushed through the system when high flows occur. This and other flow mechanisms may act to concentrate sand, increasing erosion rates in particular parts of the production system pipework.

2.3.2 Velocity, Viscosity and Density of the Fluid

The particle erosion rate is highly dependent on the particle impact velocity. It is generally accepted that the erosion rate is proportional to the particle impact velocity raised to a power, n (typically n ranges between 2 and 3 for steels).

In cases where erosion is an issue the particle impact velocity will be close to the velocity of the fluid carrying the particle. Therefore erosion is likely to be worst where the fluid flow velocity is the highest. Small increases in fluid velocity can cause substantial increases in the erosion rate when these conditions prevail.
In dense viscous fluids particles tend to be carried around obstructions by the flow rather than impacting on them. In contrast, in low viscosity, low density fluids particles tend to travel in straight lines, impacting with the walls when the flow direction changes. Particulate erosion is therefore more likely to occur in gas flows, partly because gas has a low viscosity and density and partly because gas systems operate at higher velocities.

2.3.3 Sand shape, size and hardness

Sand sizes seen at the surface depend on the reservoir geology, the size of sand screens in the well and the break-up of particles as they travel from the reservoir to the surface. Without sand exclusion measures, such as downhole sand screens, particle sizes typically range between 50 to 500 microns. With sand exclusion in place particles larger than 100 microns are usually excluded. A sand particle density of about 2600 kg/m^3 is generally accepted as being representative.

Particle size mostly influences erosion by determining how many particles impact on a surface. Very small particles (~10 microns) are carried with the fluid and rarely hit walls. Larger particles tend to travel in straight lines and bounce off surfaces. Very large particles (~ 1mm+) tend to move slowly or settle out of the carrying fluid and therefore they are unlikely to do much harm.

It is well established that hard particles cause more erosion than soft particles. There is also evidence to show that sharp particles do more damage than rounded particles. However, it is not clear whether the variability of sand hardness and sharpness causes a significant difference between the erosion rate in production systems associated with different wells or fields.

2.4 Erosion-Corrosion

Erosion damage and corrosion damage can usually be distinguished by inspection of the damaged pipework and by consideration of the operating conditions. Erosion often causes localised grooves, pits or other distinctive patterns in locations of elevated velocity. Corrosion is usually more dispersed and identifiable by the scale or rust it generates.

Erosion-corrosion is the combined effect of particulate erosion and corrosion. The progression of the erosion-corrosion process depends on the balance between the erosion and corrosion processes as demonstrated by Shadley et al[6] amongst others.

In a purely corrosive flow, without particulates in it, new pipework components typically corrode very rapidly until a brittle scale develops on the surfaces exposed to the fluid. After this scale has developed it forms a barrier between the metal and the fluid that substantially reduces the penetration rate. This is also the case when very low-level erosion is also taking place simultaneously with corrosion.

In highly erosive flows, in which corrosion is also occurring, the erosion process predominates and scale is scoured from exposed surfaces before it can influence the penetration rate. Corrosion therefore contributes little to material penetration.

At intermediate conditions erosion and corrosion mechanisms can interact. In this case scale can form and then be periodically removed by the erosive particles. This produces a pitted surface as shown in Figure 1 and can result in penetration rates of orders of magnitude greater than those caused by pure erosion or corrosion.

Erosion-corrosion mechanisms are potentially very complex, combining as they do two mechanisms that can be quite case specific. This makes prediction of erosion-corrosion penetration rates for a particular field situation very difficult. Erosion-corrosion can be avoided by ensuring that operating conditions do not allow either erosion or corrosion.

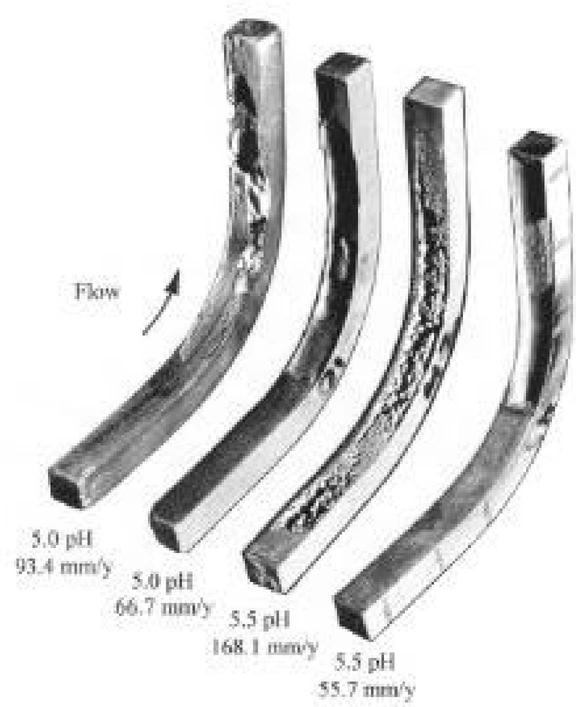


Figure 1 Pitting behaviour observed in water, CO_2, sand flows[6]

2.5 Droplet Erosion

The droplet erosion mechanism is less well understood than particulate erosion. Droplet erosion is obviously confined to wet gas and multiphase flows in which droplets can form. The erosion rate is dependent on a number of factors including the droplet size, impact velocity, impact frequency, and liquid and gas density and viscosity. As many of these values are unknown for field situations, it is very difficult to predict the rate of droplet erosion. It should also be borne in mind that control of many of these factors in laboratory-based tests is problematical. Therefore a great deal of care is required when extrapolating lab test results to field conditions.

The most practical approach is to identify whether droplet erosion could be in progress and then act to alleviate the problem. Salama & Venkatesh[5] state that solids-free erosion only occurs at very high velocities. High velocities cause unacceptably high pressure losses, therefore the conditions required for droplet erosion are unlikely to occur in correctly designed production pipework systems. They define an acceptable velocity limit to avoid significant liquid impingement erosion to be:

$$V = \frac{300}{\sqrt{r}} \qquad (1)$$

In which

V is the maximum acceptable velocity (ft/s)
? is the liquid density (lb/ft^3)

For water at STP this gives a rather conservative velocity limit of 11.6 m/s (38 ft/s). Salama and Venkatesh also collate published droplet impingement erosion threshold velocities for different steels. These values range from 26 to 118 m/s (85 to 390 ft/s).

The suggestion in RP0501[4] that droplet erosion and liquid impingement erosion is unlikely to occur in steel components at velocities below 70 to 80m/s is probably more realistic although it is not clear where these values come from. Shinogaya et al[7] published test data suggesting threshold velocities of about 110 m/s, 100 m/s and 80 m/s for water droplet impingement on stainless steel, pure iron and aluminium respectively. These results suggest that the 70 to 80 m/s limit is conservative. Svedeman & Arnold[8] state that droplet erosion does not occur at velocities less than 100ft/s (30 m/s).

2.6 Cavitation

Cavitation can be very damaging to pipework and piping components, eg valves. When liquid passes through a restriction low pressure areas can be generated, for example downstream of a sudden step. If the pressure is reduced below the vapour pressure of the liquid, bubbles are formed. These bubbles then collapse generating shock waves. These shock waves can be of sufficient amplitude to damage pipework. Cavitation is rare in oil and gas production systems as the operating pressure is generally much higher than liquid vaporisation pressures. Evidence for cavitation is sometimes found in chokes, control valves and pump impellers, but is unlikely to occur in other components.

As with droplet erosion, cavitation erosion is not well understood, and the most practical approach is to identify whether it is an issue or not and then act accordingly. Under normal operating conditions cavitation erosion is unlikely to occur in an elbow unless it is immediately downstream of a severe flow restriction (eg a choke valve).

The onset of cavitation in equipment or components with flow constrictions can be predicted by calculating a cavitation number K:

$$K = \frac{2(P_{\min} - P_{vap})}{rv^2} \qquad (1)$$

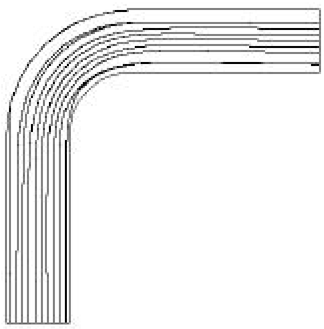
in which

P_{min} is the minimum pressure occurring in the vicinity of the restriction (Pa)
P_{vap} is the vapour pressure of the liquid (Pa)
? is the density of the liquid (kg/m^3)
v is the flow velocity through the restriction (m/s)

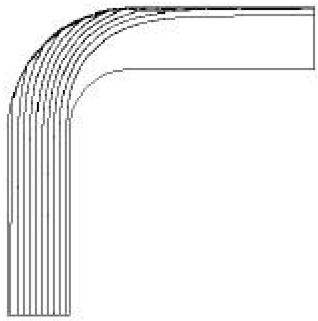
A cavitation number of less than 1.5 indicates that cavitation may occur[9].

3. EROSION EXAMPLES

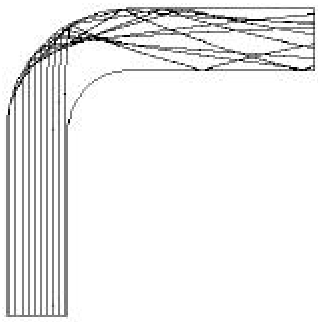
3.1 Sand Erosion in Elbows



a) Small, light particles



b) Medium particles



c) Large, heavy particles

Figure 2 The paths of different sized particles through an elbow

Figure 2 shows the paths of particles as they are carried through an elbow. The paths depend on the particle weight and the amount of drag imparted on the particles by the fluid as they pass through the elbow. Small light particles require very little drag to change direction. Therefore they tend to follow the flow (Figure 2a). Large heavy particles will have a relatively high momentum and they will hardly be deflected by the fluid flow at all. Large particles therefore tend to travel in straight lines bouncing off the elbow walls as they go (Figure 2c). Figure 2 can also be viewed by considering particles of a fixed size in fluids with different properties. Figure 2a could therefore represent particles in a highly viscous, dense fluid and Figure 2c could represent particles in a low density, low viscosity fluid (for example a gas at low pressure).

Figure 2a shows particle paths typically seen for small sand grains (of the order of 10 microns) in a liquid flow. Figure 2b is representative of typically sized sand grains (of the order of 200 microns) in liquid flows and Figure 2c is representative of typically sized sand in gas flows.

In general, the wear scar is located on the outside of the elbow, however, in liquid flows the scar may be swept round to the inside, downstream surface. Occasionally, weld intrusions immediately upstream of an elbow cause a recirculation zone on the inside radius of an elbow.

This scenario can generate a localised wear spot on the inside of the elbow that will erode very quickly.

The location of maximum penetration for a 1.5D radius elbow is at about 45° from the elbow inlet for gas flows and at about 90° for liquid. The length of the erosion scar increases with elbow radius and the depth decreases[10].

For a given flow velocity and with all other factors equal, the erosion rate in gas is likely to be considerably higher than that for liquid as more particles will impact on the outside of the elbow. The maximum wear location and the penetration rate with multiphase flows are often intermediate, but this depends heavily on the multiphase flow regime. CFD simulations run in the investigative part of this project suggest that annular flow through restrictions may concentrate particle impacts on components downstream, accelerating the erosion rate beyond that which would occur in a simple gas-particle flow.

3.2 Sand Erosion in Blind Tees

Blind tees are generally perceived as being less prone to erosion than standard 1.5D radius elbows and consequently some operators routinely replace elbows with heavy weight blind tees when erosion problems are suspected.

If a blind tee is orientated correctly and the flow conditions allow it, a sand plug can build up in the dead leg of the tee. Particles passing through the tee tend to impact into this plug instead of on the walls and consequently erosion is reduced. However, this plug may also prevent corrosion inhibitor reaching the wall leading to corrosion problems. If the plug does not form when, for example, the blind tee is vertical, or when fluid drag is high enough to keep the particles suspended. Under certain circumstances particles concentrate and recirculate in the blind leg, scouring its internal surface and generating significant erosion[11]. Alternatively, specially designed “target tees” are used in which the dead leg of the tee includes a layer of soft material (usually lead) that absorbs the energy of particle impacts.

4. ESTIMATION AND AVOIDANCE OF EROSION

This section reviews methods of managing erosion. Section 4.1 introduces various management techniques and Section 4.2 gives an overview of different guidance documents and standards. One important aspect of managing erosion is establishing the scale of the problem and hence the amount of effort required to avoid failures. Section 4.4 assesses predictive methods that give an insight into the rate of erosion in pipework systems.

4.1 Erosion Management Techniques

A number of measures can be taken to monitor and avoid erosion. These include:

4.1.1 Reduction of Production Rate

Reducing the production rate reduces both the sand production rate and the flow velocity through the pipework. However this has obvious financial implications.

4.1.2 Design of Pipework

Pipework should be designed to minimise flow velocities and avoid sudden changes in flow direction (e.g. at elbows, constrictions and valves). The use of full bore valves and blind tees in place of elbows can also reduce erosion problems. Slugging flows can be particularly damaging therefore the inclusion of slug catchers and drains may be appropriate for certain installations.

Thick-walled pipes are often used to increase the wear life of pipework. However, care should be taken, when doing this, as increasing wall thickness reduces the pipe bore, elevating flow velocities and increasing the erosion rate, particularly with small bore pipework.

4.1.3 Sand Exclusion & Separation

Downhole sand screens and gravel packs are often used to stop sand entering the production system. These tend to be used on new wells in which sand production has been identified as an issue. Typically, sand screens prevent particles larger than 100 microns from entering the production stream. However, sand screens increase the resistance to flow entering a well and consequently affect its potential productivity. There is therefore a balance to be struck between reducing productivity by including a sand screen and having to choke-back an unprotected well to avoid excessive sand production. Also, if produced in large enough numbers, even very small particles can generate a significant degree of erosion, therefore sand screens and gravel packs do not guarantee erosion-free operation.

Occasionally sand separation devices, such as hydrocyclones and other types of desander, are used to reduce erosion in components downstream of the wellhead. These devices can be very effective at protecting chokes in particular. However, they do not protect downhole equipment. As with sand exclusion measures, the inclusion of a sand separation device in the production stream is likely to have an adverse impact on production economics. It also increases the amount of pipework within the production system and therefore may increase the exposure of the system to erosion problems.

4.1.4 Measurement & Estimation of Sand Production

Sand collection in separators is often used as an indication of sand production. Sand production is usually associated with geological factors and hence if one well in a field is known to produce large amounts of sand then other wells are suspect.

Sand monitors are used when erosion problems are suspected although there are very variable reports as to their effectiveness. This may be due to limitations of current technology, incorrect operation or unrealistic expectations of the users.

Some sand monitoring devices are located downhole on the production tubing. More commonly monitoring is undertaken on the topsides. Two generic types of device are used to monitor sand production. These are probes inserted through the pipe wall into the flow, and non-intrusive devices clamped onto the pipe wall.

Insertion sand probes

a) One end of the probe is attached to a high pressure access fitting on the outside of the pipe. The other end is a sealed thin-walled stainless steel tube placed within the process stream. As sand impinges on the element a hole is eventually eroded through the element wall. Once penetration has occurred the system pressure is transferred to either a pressure gauge or pressure sensor. The pressure device indicates that the element has been breached. These devices therefore give an "unbreached" or "failed" output.

   This type of device does not give any indication of erosion rate but only that failure has occurred. The relationship between the point at which the probe fails and the continuing erosion in the system, particularly at critical points, needs to be carefully addressed.

b) Other types of insertion probe are used for continuous monitoring.

   One type uses an acoustically sensitive crystal to generate an electrical pulse when the inserted portion of the sand probe is struck by a particle of sand. Operation is at ultrasonic frequency to control interference from background flow noise. The energy of the pulse is processed to estimate the amount of sand in the flow stream.

   The other type is based on measuring the change in electrical resistance of sensing elements that are eroded by the sand. The measured metal loss is processed to indicate a sand production rate. Sand probes can be periodically polled by a main processor, the data on the quantity of produced sand being transmitted to a data acquisition unit for display and trending.

Clamp-on sand probes.

These devices are strapped to the outside of piping, often downstream of an elbow. They are acoustic devices that detect the sound of particles impacting the pipe wall. However careful positioning of the device is essential as choke noise can swamp the signal. However, downstream of the choke is where velocities and hence erosion are highest. Ultrasonic devices claim to distinguish between sand generated and flow generated noise. The devices are also said to be insensitive to mechanical and structural noise. Acoustic particle monitors can detect particles down to about 15? m in size.

Located on the outside of piping these instruments are not affected by the process fluid, however intimate contact with the pipe wall, by means of secure clamps, is critical.

Software prediction tools are available which use data from continuous monitoring devices to predict erosion rates in process pipework.

Sensitivity of the continuous monitoring type of sand probes in dry gas streams is typically ±0.1 kg/day and in oil streams ±0.1kg/100m^3. Calibration of the devices is essential; this will ideally be done in situ by volumetric measurement of sand rate in real time for the flowing stream.

4.1.5 Wall thickness measurements

Ultrasonic thickness probes are often used to gauge material loss in eroding pipework. The primary limitation of this technique is that it only checks a limited region of the pipe. As erosion scars in elbows generally occur on the outer radius of the elbow between about 30° and 90^o and this is the most obvious place to look for erosion damage. However, the flow disturbances upstream of the elbow, such as other elbows, valves or flow constrictions may act to move the location of maximum erosion, making it difficult to detect.

Tests at NEL have shown that, in a 2" elbow, ultrasonic thickness probes can measure wall thickness to about ±0.2 mm. These measurements can easily detect a scar of the order of 1 cm^2 in area and 0.7 mm deep. However it is unclear whether these probes can detect small but deep "pinhole" type defects. Also, as elbows are often extruded there is a natural variation in wall thickness around the radius of the bend and a variation between different elbows even when no erosion has taken place. Therefore careful repeat measurements are needed to spot the progressive reduction in wall thickness caused by erosion. Obviously, if these surveys are not carried out regularly enough or data is not properly stored or analysed then erosion problems are likely to be missed. An adequate survey strategy is therefore required.

4.2 Guidance in Standards and other Information Sources

This section provides a brief review of standards, recommended practices documents, current practices and key papers giving information on erosion in oil and gas production systems.

Brief discussions with a cross section of users of pipework design codes had found that attitudes to erosion are quite variable. Some companies go to great lengths to ensure that their installations do not suffer from erosion problems whereas others do little to address erosion issues.

BP have produced a CD ROM (Corrosion and Material Guidelines 2001) that includes a section on erosion prediction. An example flow chart, showing a method by which erosional velocities may be assessed is provided in Appendix II.

The approach taken by the Health & Safety Executive to sand management is given in an OSD Permanent Background Note (PBN 99/7). In particular regulations relevant to erosion and sand control measures are outlined in Appendix III, which is an extract from PBN 99/7.

The design of pipework for offshore oil and gas installations is outlined in API14E[12] and BS EN ISO 13703:2001[13]. Both of these documents define a limiting velocity below which erosion will not take place. The use of sand probes, capped or target tees and periodic pipe wall thickness surveys are recommended where solids are likely in the flow. They also state that short radius elbows should not be used.

The design of subsea production systems is outlined in the BS EN 13628[14] and API 17 series of standards. In general, these standards do not give specific guidance on erosion prediction or management. However, API17B[15] (which covers the use of flexible pipe subsea) recommends the use of erosion resistant materials for sandy service. It also recommends that testing is required to adequately prove the effectiveness of this measure.

BS EN ISO 14692-3[16] gives recommendations on the design of GRP piping. In this case it recommends a normal maximum flow velocity of 5 m/s for liquids and 10 m/s for gases in GRP pipes. Sudden changes in flow direction and internal weld beads at pipe joints are to be avoided.

DNV RP 0501[4] is one of the most comprehensive available on erosion management. It gives design guidelines on straight pipes, welded joints, reducers, elbows and blind tees.

Venkatesh[1] gives a good introduction to erosion mechanisms and Salama[17] summarises different modelling techniques currently being applied in this field. Reviews of liquid droplet erosion are provided by Hammit[18] and Heymann[19].

4.3 Sand Erosion Prediction Methods

The most sophisticated modern particulate erosion models consider the erosion process in three stages. Initially the flow of the carrier fluid through the elbow or fixture is modelled or in some way approximated. This flow prediction is used to derive the drag forces imparted by the fluid on the particles, hence the trajectories of a large number of particles are predicted. When individual particles impact on a wall the damage done is calculated using a material-specific empirical, or a theoretically derived impact damage model. The average impact damage of a large number of particles can then be used to predict the distribution and depth of erosion damage on a surface.

There are a number of variations on this theme. In most cases, impact damage models have a similar basis. However a number of alternative methods have been used to calculate particle trajectories. Computational Fluid Dynamics (CFD) software has regularly been used to model the fluid flow and particle trajectories. It has been shown to be good at predicting erosion locations and erosion scar shapes. It is particularly advantageous in complex geometries such as valves, in which particle trajectories are very convoluted and complicated.

Elbows are relatively simple shapes and therefore a number of alternative, empirically or theoretically derived, particle trajectory models have been used instead of CFD. The simplest of these assumes that particles travel through the elbow in a straight line (in a similar manner to that shown in Figure 2c) and that the first wall impact is the most damaging. This is a reasonable first order approximation in gas flows. However in liquid flows particles are dragged round the elbow by the liquid (as shown in Figures 2a and 2b and discussed in Section 3) and the straight particle path approximation becomes worse. More sophisticated trajectory models correct for drag effects in higher viscosity fluids.

Probably the simplest and most commonly used erosion model for elbows in production systems is given in API 14E[12]. This model defines an acceptable mean pipeline flow velocity as being –

$$V = \frac{C}{\sqrt{r_m}} \qquad (3)$$

In which

V is the maximum acceptable velocity (ft/s)
$?_m$ is the gas/liquid mixture density (lb/ft^3)
C is a constant

The value of the C factor depends on the service required from the pipes.

API 14E suggests a C value of 100 is acceptable for corrosive service and 150 to 200 for inhibited systems. Higher values may be appropriate for erosive service, although these values are not specified. There has been much debate about appropriate values for C and different oil companies use different values for different applications[17]. However, although this equation is often applied it is widely accepted to be misleading or incorrect [1, 5,17]. It does not account for the physical phenomena governing the erosion process and its origins are obscure.

Alternative methods have been suggested by a number of workers. Many of these are based on an impact damage model of the form –

$$E = AV_p^n F(a) \qquad (4)$$

in which

E is the erosion rate (kg of material removed/kg of erodant)
V_p is the particle impact velocity
A is a constant depending on the material being eroded and other factors.
a is the particle impact angle
F(a) is a material dependent function of the impact angle between 0 and 1
n is a material dependent index

Huser & Kvernvold[20] use an impact damage equation of the form -

$$E = m_P K V_p^n F(a) \qquad (5)$$

In which

m_p is the mass flow of particles impacting on an area
K and n are constants given for steel and titanium grade materials and GRP

Values of K, n and F(a) are derived from sand-blasting tests on small material samples[2]. Figure 3 shows the angle relationship F(a) used by Huser & Kvernvold.

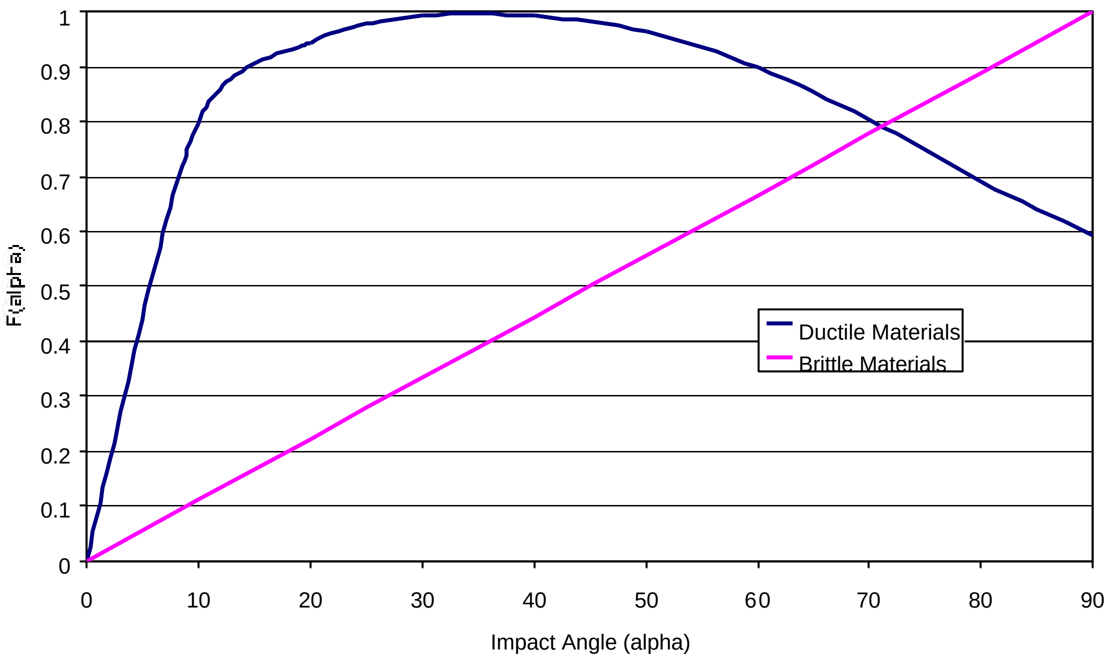


Figure 3 F(a) relationship used by Huser & Kvernvold[20] for ductile and brittle materials

This model has been used with both CFD particle models and with various empirical particle models. RP0501[4] compiles these empirical particle models for the calculation of sand erosion in straight pipes, around welds, in elbows, tees and reducers. These can be used in hand calculations or via a commercial software package, ERBEND. These models can also be applied to multiphase (liquid/gas) flows by calculating equivalent mixture viscosity and density.

Salama & Venkatesh[5] use similar methods to those of Huser & Kvernvold, although they simplify their model by making the conservative assumption that all sand impacts occur at about 30^o and hence they set F(a) to 1. This approximation is reasonable for gas flows, but does not account for particle drag effects in liquid flows. Hence the following equation is derived –

$$ER = \frac{S_k W V^2}{D^2} \qquad (6)$$

ER is the erosion rate (thousandths of inch per year)
W is the sand flowrate (lb/day)
V is fluid velocity (ft/sec)
D is the pipe diameter (inches)
S_k is a geometry dependant constant

S_k = 0.038 for short radius elbows
S_k = 0.019 for ells and tees

In comparison with experimental air-sand tests of elbows[21] this method was found to be consistently conservative, the predicted erosion rate being on average 44% greater than the measured value.

Svedeman & Arnold[8] also suggested using equation 5. Basing their work on correlations developed by Bourgoyne[7] they gave values of S_K for gas systems of:

S_k = 0.017 for long radius elbows and ells
S_k = 0.0006 for plugged tees

Salama[17] stated that equation 5 is not particularly accurate when applied to gas-liquid systems and developed a new equation:

$$E_p = \frac{1}{S_p} \frac{V_m^2 d}{D^2 r_m} \qquad (7)$$

In which -

E_p is erosion in mm/kg

D is the pipe diameter (mm)
d is the particle diameter (microns)
V_m is the mixture velocity (m/s) defined by $V_m = V_{liquid} + V_{gas}$
$?_m$ is the mixture density defined by $?_m = (?_{liquid} V_{liquid} + ?_{gas} V_{gas})/V_m$
S_p is a geometrical constant

This equation is intended to account for particle size and liquid effects. Calibrating against experimental data from Weiner & Tolle[21] and Bourgoyne[22] produces constants –

S_p = 2000 for elbows (1.5D and 5D)
S_p = 12000 for ells,
S_p =25000 for plugged tees (liquid gas) and 500000 for plugged tees (gas)

A significant amount of work on pipe component erosion has been performed at the University of Tulsa Erosion Corrosion Research Center (E/CRC). A range of particle models have been utilised with an impact damage model of the form:

$$E = F_M F_S m_P V_p^n F(a) \qquad (8)$$

In the above equation the F_M coefficient accounts for the variation in material hardness. McLaury & Shirazi[23] give typical values of Fm for a number of different steels ranging from 0.833 to 1.267, suggesting a ±25% in erosion resistance between different steels. These values have been derived from sand-water jet impingement tests[24] and air-sand tests[21] in which distinct hardness effects were seen. Other workers, such as Haugen et al[2] and Wallace[25] suggest that the variation in erosion resistance between different grades of steel is negligible compared to the spread of data points inherent in erosion tests.

The F_S coefficient accounts for sand sharpness, a value being given as 1, 0.53 and 0.2 for sharp, semi-rounded and rounded grains respectively. A value of 0.53 is used to represent production systems. Again, other workers do not tend to account for sand sharpness.

Early work with this model[24, 26, 27] used an empirical particle tracking model that used the concept of an "equivalent stagnation length" to convert erosion characteristics derived from direct impingement tests to apply to tees and elbows. This method accounts for the effect of liquid on particle paths.

Comparison against tests on ½" elbows showed that the procedure slight under-predicted erosion[24]. Further developments saw this method applied to multiphase flows and comparison with gas, liquid and gas-liquid tests by Bourgoyne[22] and Salama[17] showed under and over-predictions with a typical discrepancy of about 30% although some predictions were more than 100% out.

Wang et al[28] used the Tulsa impact damage model (equation 7) with a two-dimensional CFD-based particle model. Edwards et al[29] performed a similar analysis using a three-dimensional CFD code to investigate erosion in long radius elbows and tees. Both achieved good agreement with Eyler's data[30] and Wang's predictions also agreed well with Bikbiaev[31]. However predictions in both of these papers are normalised, making it unclear as to how well the maximum erosion rate was predicted.

Elbow erosion models for multiphase flows have also been developed by Birchenough et al[32, 33]. The original model was entirely based on experimental correlations. However, limitations of this model have lead to the development of a second model. This model has been implemented in software known as Sman3.9, however, details about it have not been published.

Elbow erosion has recently been studied at NEL using methods developed by Wallace[25]. This work entails using three-dimensional CFD particle models to assess the influence of upstream valves on elbow erosion. An empirical impact damage model was used that was based on direct water-sand and air-sand impingement tests over a velocity range of 15 to 200 m/s. Haugen et al's[4] erosion damage model was also used in this work.

4.4 Comparison of Erosion Predictions for Elbows

This section compares how different methods predict erosion in a 2” elbow under three different flow conditions; a sand-methane flow, a sand-condensate flow and a sand-air flow. The latter of these is compared against the results of an experimental test run in the NEL abrasive flow facility.

Calculation methods include CFD simulations using the erosion damage models of Wallace[25] and Haugen et al[2], calculations by Sman3.9 software that embodies the work of Birchenough et al[32, 33], and methods described in RP 0501[4], Salama[17], Salama & Venkatesh[5] and McLaury & Shirazi[23]. API acceptable velocity limits are also shown.

Figure 4 shows the predictions for the sand-methane mixture. The main parameters used are as follows –

- Gas Density = 4.82 kg/m^3
- Gas Viscosity = 1.1 x 10^{-5} Pas
- Sand particle size = 150 microns
- Sand density = 2650 kg/m^3
- Elbow diameter = 55 mm
- Elbow r/D = 1.5
- Elbow material steel grade (Brinnell Hardness = 210)
- Sand concentration = 21.6 ppmw

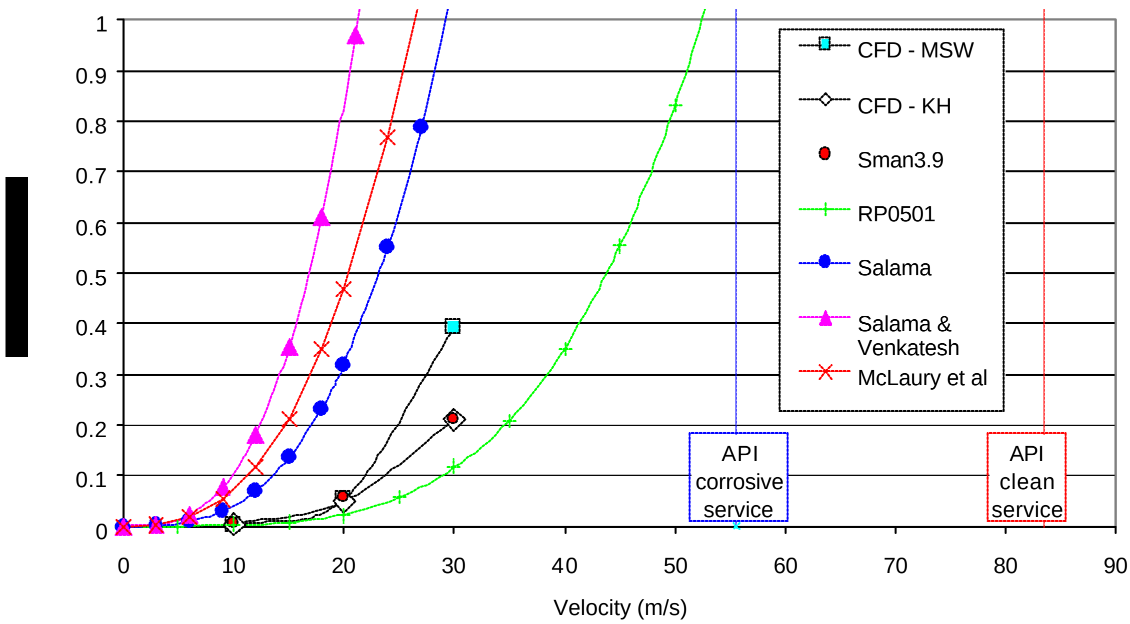


Figure 4 Erosion of a 2” elbow in methane-sand flow

There is very good agreement between the CFD predictions using the Haugen et al impact damage model and the Sman3.9 model. Salama, Salama & Venkatesh and the McLaury &

Shirazi methods all predict much higher erosion rates. The API corrosive flow velocity limit is very high in relation to the erosion predictions shown.

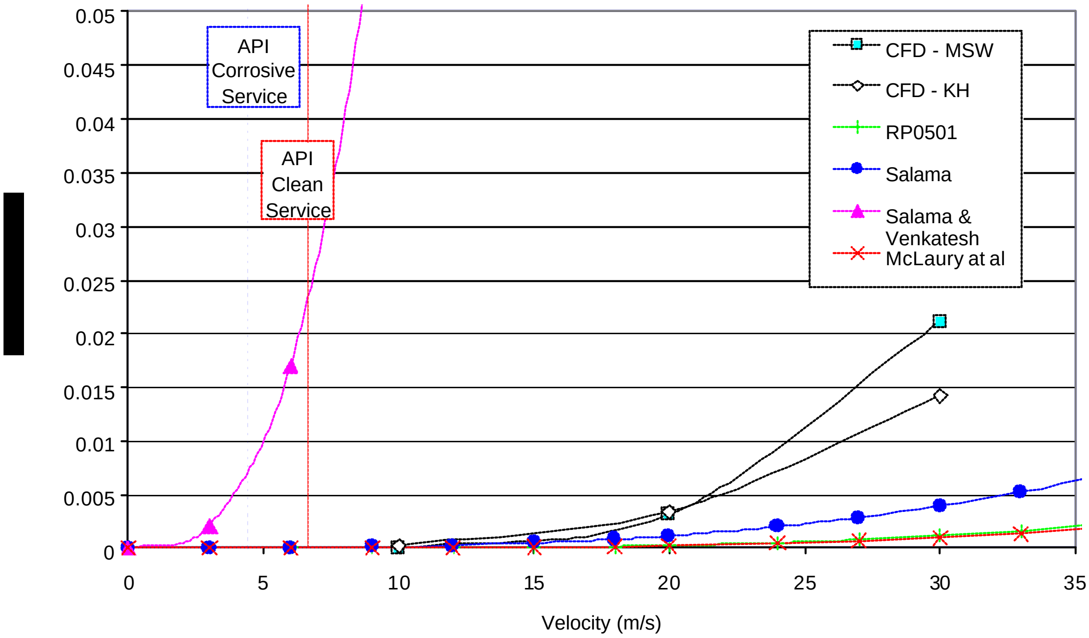


Figure 5 Erosion of a 2” elbow in liquid-sand flow

Figure 5 shows predictions of erosion for the 2” elbow in liquid at the following conditions:

- Liquid Density = 769 kg/m^3
- Liquid Viscosity = 1.08 x 10^{-3} Pas
- Sand particle size = 150 microns
- Sand density = 2650 kg/m^3
- Elbow diameter = 55 mm
- Elbow r/D = 1.5
- Elbow material steel grade (Brinnell Hardness = 210)
- Sand concentration = 0.1 ppmw

The Salama & Venkatesh predictions are very high. This is not surprising as this model does not account for liquid drag effects and is widely acknowledged to over-predict erosion in liquid flows[17]. The Salama, RP0501, McLaury and CFD models all respond to the liquid drag effects. In this case there is good agreement between the McLaury and RP0501 models. In this case the API corrosive service limit appears to be very conservative.

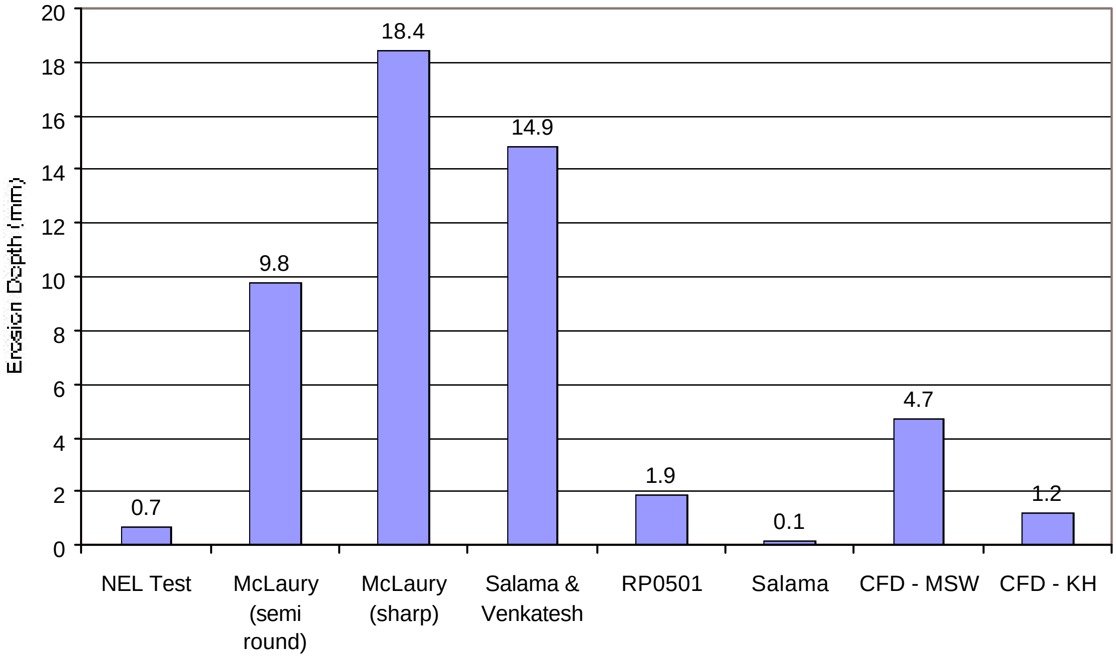


Figure 6 Erosion of a 2" elbow in air-sand flow

Figure 6 shows predictions of erosion for the 2" elbow in air at the following conditions:

- Gas Density = 1.225 kg/m^3
- Gas Viscosity = 1.0 x 10^{-5} Pas
- Sand particle size = 250 microns
- Sand density = 2650 kg/m^3
- Elbow diameter = 55 mm
- Elbow r/D = 1.5
- Elbow material steel grade (Brinnell Hardness = 210)
- Sand mass flow = 500kg at 40m/s + 250kg at 50m/s

Also included in Figure 6 is the maximum measured erosion of an elbow tested at these conditions. As in the methane test case the McLaury & Shirazi and Salama & Venkatesh methods produce similar high results and the CFD and RP0501 methods have much lower predictions, agreeing much better with the test. The Salama method significantly under predicts the erosion rate. In this case the API corrosive velocity limit is very high (110 m/s).

This exercise demonstrates the inconsistency of modern elbow erosion prediction methods. Most of the methods tested do account for factors such as changes in fluid viscosity and density in some degree. However their predictions can be orders of magnitude different. In particular the API velocity limit gives very variable results, producing very high limits for gas and very low limits for liquids. This is in line with the findings of McLaury & Shirazi[23] amongst others.

5. CONCLUSIONS

1. Erosion can be generated by a number of phenomena:
   - Particulate erosion
   - Liquid droplet erosion
   - Erosion-corrosion
   - Cavitation

   Of these, particulate erosion by sand is most likely to cause erosive failures in oil and gas production systems.

2. Any part of the pipework system that experiences high flow velocities or sudden changes in flow direction is vulnerable to erosion. Erosive failures also often occur at elbows. Although elbows generally experience less hostile conditions they are rarely designed to resist erosion.

3. The degree of erosive damage at a given flow velocity is proportional to the mass of sand passing through a component. This in turn depends on whether sand is transported through the component or whether the sand bypasses the component in a parallel stream, as can occur in complex pipe networks. Any factor that increases sand flow through a component will increase its erosion rate.

   The following phenomena are likely to increase the erosion rate in a particular component:

   - Increases in the sand production rate
   - Changes in flow rate that cause more sand to be transported through the component
   - Changes in multiphase flow regime that cause more sand to be transported through the component
   - Periodic changes in flowrate (for example a shutdown) that allow sand to gather and then to be carried through the component at a later time when flow conditions have changed

4. Any factor that acts to concentrate sand impacts onto a small part of a component will increase its erosion rate. For example:

   - Annular (liquid-gas) flows may concentrate particles near the walls
   - Droplets may encapsulate particles and cause them to impact on a small area
   - Upstream flow restrictions may concentrate particles into a jet that impacts onto a small area
   - Upstream component combinations that cause the carrying fluid to swirl may concentrate particles into spiralling “ropes”

   However, it should be noted that these effects are quite specific to individual installations and they are difficult to predict without a detailed flow analysis or testing. For example, there is evidence to show that annular flow may effectively cushion particle impacts and reduce erosion in some circumstances.

5. The rate of particle erosion is highly dependent on the flow velocity through a component. As a rough estimate:

   Erosion Rate a Velocity^n

   Where the value of n is between 2 and 3 and the eroding material is a ductile metal or higher for hard brittle materials. Small increases in velocity can therefore cause substantial increases in erosion. In high flowrate systems relatively small amounts of sand can cause a significant amount of erosion.

6. It is an over-simplification to say that sand particles below a given size do not cause erosion. As they are lighter, small particles more readily follow the flow of the carrying fluid rather than impacting on the walls. Also, when they impact they tend to do so at low angles and they cause less damage. However, if they are present in large enough quantities in high velocity gas flows, particles smaller than 100 microns can still cause a significant degree of damage.

7. Drag forces on sand particles are different in liquids and gases. Erosion rates in gas flows are usually greater than in liquid flows operating at the same velocities. Also, the erosion scar position will be different. However, oil wells often produce more sand than gas wells and are equally prone to erosion problems.

8. Erosion in multiphase flows is often intermediate between liquid and gas flows. However, multiphase flow effects are complex and there is some evidence to suggest that annular flow through restrictions may concentrate particle impacts on components downstream, accelerating the erosion rate beyond that which would occur in a simple gas-particle flow.

9. A number of design standards have been reviewed to assess their recommendations on erosion avoidance.

   - The recommendations given in API 14E and BS EN ISO 13703:2001 (both covering pipework for offshore installations) are highly conservative for liquid flows and under estimate the potential for erosion in gas flows.
   - BS EN 13628 and API 17 (general standards covering subsea production systems) do not give specific guidance on erosion.
   - API17 B (covering flexible subsea pipework) recommends erosion resistant material sand testing for erosive service
   - DNV RP0501 is specifically aimed at pipework in erosive service and it provides detailed guidelines on elbows and other components.

10. A lot of work has been done on particulate erosion and the erosion process in elbows is well understood on a qualitative level. A number of simple calculation techniques have been developed to predict the rate of erosion in pipe components (mostly elbows). Comparison of different methods has shown significant discrepancies in their results. This is largely caused by the simplifications required to make these methods usable.

Calculations of this type can be used to assess the degree of erosion likely in a production system. However, given the variability of their predictions they should only be assumed to give an indication of the order of magnitude of erosion.

If the results of this type of analysis indicate a likelihood of erosion problems then a detailed erosion study based on CFD and experimental testing methods is recommended. In particular a detailed study is recommended where a number of components are installed in close proximity to each other (e.g. a sequence of elbows with little straight pipe between them) or when any kind of restriction (e.g. a check valve, reducer or reduced bore valve) is part of the system.

11. Erosion is a complex subject and there is still much uncertainty in erosion quantification and control techniques in the following areas:

- How the erosion of a component is affected by the pipe configuration and other components upstream of it.
- The way in which sand is transported through production systems
- Erosion mechanisms in multiphase and wet gas flows.
- Quantification of erosion-corrosion damage in production systems
- Validation and inter comparison of CFD and other predictive methods
- The effective application of sand monitors

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APPENDIX I

Summary of Dangerous Occurrence Incidents 1993-2001 associated with erosion of elbows

Year	Installation	Incident Summary
1992	MODU	Flaring gas from well when gas leak in 3" elbow feeding flare noticed. Operation at the time was a post perforation clean up of the well through the well test equipment. Well was cleaning up on a 44/64" adjustable choke at the steam exchanger. Elbow approx 4 feet upstream of the starboard boom washed out causing a release of gas.
1993	Fixed	Normal process operations, with no untoward alterations were ongoing. Condensate pump "c" was the single duty pump. A mechanic working in the area noticed a spray of condensate coming from under the ram box cover. He informed operations and the area operator shutdown the pump, isolated the system and vented the residual to drain. On investigation it was found to have been caused by a pinhole leak from the outer radius of a 6 mm dia s/s tube which is part of the condensate throat bush flushing system ram packings.
1993	MODU	The fluids flowing from the well were dry gas, water, sand and abrasive drilling fluids, cutting the 90 elbow to the flare boom. Thus causing a minor hydrocarbon release.
1993	Fixed	During a planned shutdown liquids were being removed from the production systems using residual pressure. After pumping out the condensate surge drum to its minimum level it was decided to utilise the closed drain system to fully drain the vessel. The operator, having operated the appropriate valves heard a change in noise level and upon investigation saw a slight mist on the mezzanine level below and immediately isolated the line. Simultaneously the control room operator reported a single 20% lel detection in the same area. On investigation sand was evident on the cellar deck floor and the hole in the process line 2” elbow identified.
1994	MODU	Excessive carry over of formation sand, through sand filters, combined with high flowline velocities caused erosion to three elbows and one xo in two incidents (01:40 and 08:15hrs) situated in the gas line. This resulted in a small gas escape.
		CCR reported low gas in v45 area (gas head g119) first indications

1995	Fixed	the gas detected was coming from p119 leaking seal. Pump was isolated, gas reading in CCR continued up to 30 lel. Further checks in the area were carried out and a hole was found in an elbow on the 2" drain line to v45 leaking gas.
1995	Fixed	Preparing all the platform processes for annual s/d work an 8 mm hole was discovered/created on the gas injection header blowdown pipe- work in u4ee. The loss of hydrocarbon containment which resulted in a llg alert (yellow) occurred during manual de-pressurisation of bd27 above the sssv via the injection header blowdown valve. The leak was discovered almost immediately and the area technician closed the blowdown valve which reduced the leak to a small backfeed of gas from the platform flare system. All processes were s/d at this time, however de-pressurisation was ongoing in various areas. The hole is situated on the first 90 deg bend on the blowdown line and 100 v 470. It is approx. 250 mm downstream of cv9324. The hole is attributed to sand erosion. Actions taken/planned to prevent recurrence of incident.
1995	MODU	During the clean up flow of well 44/22a d6-05 a 96' elbow (6") started to wash downstream of choke manifold. The choke manifold was manned at all times. The leak was seen and choke closed in immediately according to safe working practices. The leak was caused by well fluids/solids causing erosion to lines.
1996	Fixed	Prod ops were preparing the test separator for maintenance, it was isolated from the wells and oil displaced by flushing with water. This was being depressurised. When pressure was approx 4 bar the sandwash down comer developed a leak at the bend under the separator allowing sand water and some gas to escape into the module setting of a low gas alarm. The operators depressurised the separator to the flare.
1996	Fixed	Normal production. Natural ventilated module. Crude oil escape, approx 20 lts. Elbow on manifold developed pin hole leak which increased to approx. 1/8th.inch. Detected by area operator who shut well in and drained manifold to make safe.
1998	Fixed	During post fracturing well clean up of well the ½-inch heavy wall s/s pipe work which formed the depressurisation line from the temporary proppant catcher to the lp flare header failed. Failure occurred through erosion of two[2] 90 degree bends due to particulate matter in high velocity gas.
1999	Fixed	Normal production . Hydrocarbon gas. During routine production monitoring of gas processing area the production supervisor noted/heard sound of gas/air escaping - subsequent inspection of the area revealed small pinhole type leak

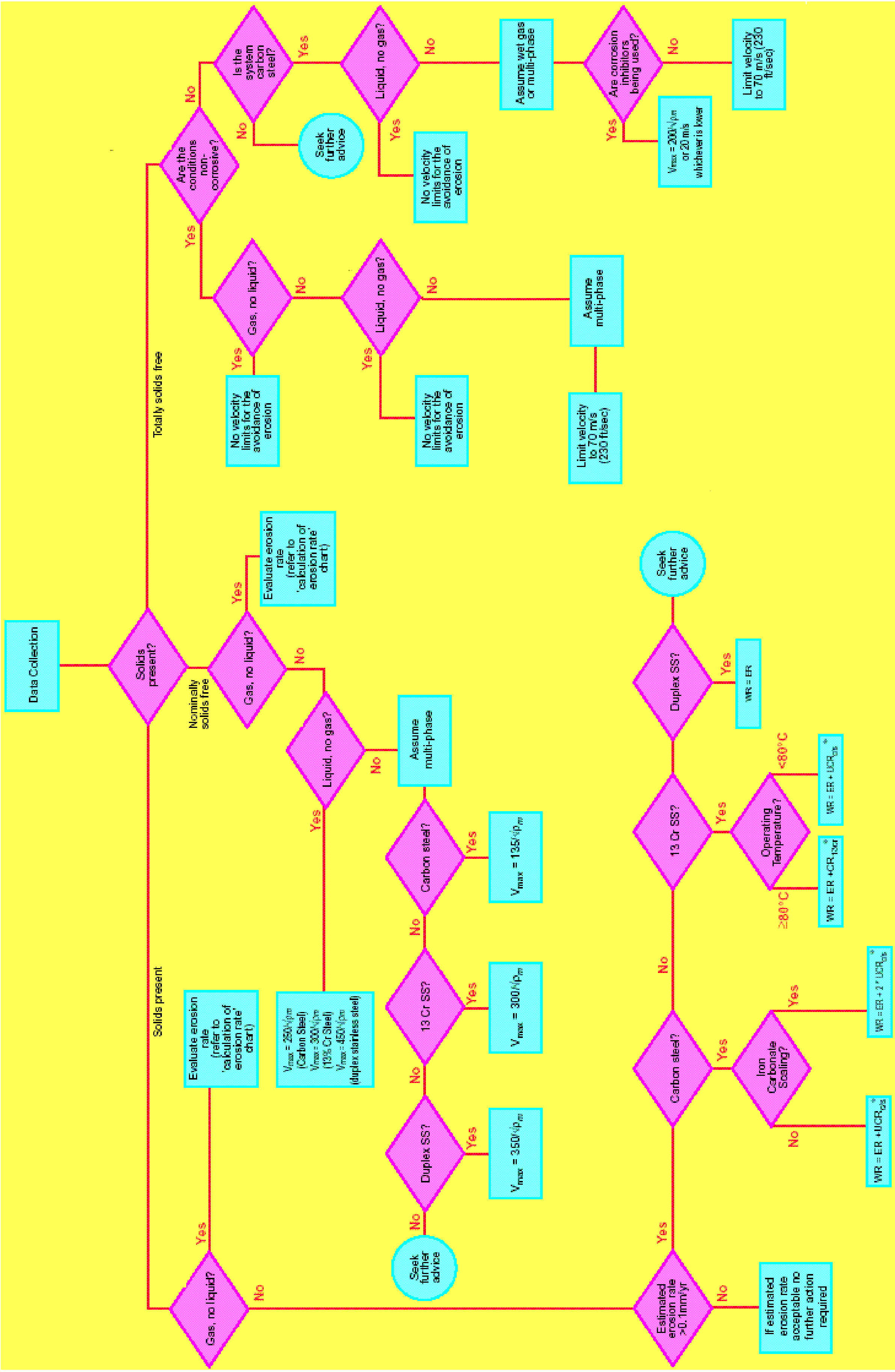
		on a 1" elbowlet, location on the bend of 8" gas line to gas compression second stage discharge scrubber. Subsequent NDT inspection showed no wall thinning of the gas line, the defect area showed original weld preparation had created minor raised area in the line of gas flow causing some turbulence of gas/liquid and subsequent area of erosion.
2000	Mobile	During well-testing operations on well a small hydrocarbon gas release took place. The well was in the process of being beaned up. A small hole developed in a 90-degree elbow on the outlet on the heat exchanger. A gas/water plume of approximately 1' by 4' was observed. Upon investigation of the elbow a hole measuring 3.0 by 0.5 millimetre was discovered. The pressure regime in the 4" elbow was 150 lbf/in² at the time of the leak. Cause of the leak is sand production leading to erosion damage.
2000	Fixed	During normal operations, a small pinhole leak developed in 3" duplex pipe downstream in a reducer (1 1/2" - 3") on the cyclone water recirculation system. The leak was detected by operator observation at a very early stage and a small amount of oil (less than 1kg estimated) was lost in conjunction with the mainly produced water stream. Little gas was evolved as the process is reduced to lp pressure prior to recycle. The system was immediately isolated using both xsv and local valve isolations and the pipe removed for inspection/repair. First indications are that erosion of the pipe had taken place perhaps due in part to the system also containing varying quantities of sand.
2000	Fixed	During routine platform inspection by the production supervisor a small pinhole leak was observed from an elbow on the 4-inch gas line from the test separator to the flare knock out drum. Production was shutdown as was gas import. A full isolation was effected following formal risk assessment.
2001	Fixed	A wire line crew on an installation heard a loud resonance coming from another installation 1 km away. Standby vessel was sent to investigate and reported a large mist cloud. Investigation team found a 2-inch liquid drain line had been cut out by sand and an elliptical hole 18 mm x 16 mm was present at an elbow.

[1] *Washout = Severe erosion causing loss of metal sufficient to penetrate through the wall thickness, leading to loss of containment*.

APPENDIX II

Flow Chart for Assessment of Velocity Limits for Avoiding Erosion

The following flow chart is taken from a CD ROM produced by BP "Corrosion and Materials Guidelines 2001". This CD ROM is available on request from Bill Hedges email: hedgesb@bp.com. The chart is included as an example of a typical erosion assessment method may be developed for use in hydrocarbon production systems. This chart should not be used without further reference to the original BP document.



Data Collection
Solids present?
Totally solids free
Nominally solids free
Solids present
Are the conditions non-corrosive?
Is the system carbon steel?
Seek further advice
Liquid, no gas?
No velocity limits for the avoidance of erosion
Assume wet gas or multi-phase
Are corrosion inhibitors being used?
Limit velocity to 70 m/s (230 ft/sec)
$V_{max} = 200/\sqrt{\rho_m}$ or 20 m/s whichever is lower
Gas, no liquid?
Assume multi-phase
Limit velocity to 70 m/s (230 ft/sec)
Evaluate erosion rate (refer to 'calculation of erosion rate' chart)
Carbon steel?
$V_{max} = 135/\sqrt{\rho_m}$
13 Cr SS?
$V_{max} = 300/\sqrt{\rho_m}$
Duplex SS?
$V_{max} = 350/\sqrt{\rho_m}$
$V_{max} = 250/\sqrt{\rho_m}$ (Carbon Steel) $V_{max} = 300/\sqrt{\rho_m}$ (13% Cr Steel) $V_{max} = 450/\sqrt{\rho_m}$ (duplex stainless steel)
Estimated erosion rate >0.1mm/yr
If estimated erosion rate acceptable no further action required
Iron Carbonate Scaling?
$WR = ER + UCR_{cs}$*
$WR = ER + 2 * UCR_{cs}$*
Operating Temperature?
≥80°C
<80°C
$WR = ER + CR_{13cr}$*
WR = ER

APPENDIX III

Regulations and Guidance

(Extract from OSD Permanent Background Note: PBN 99/7 Produced Sand Management)

Safety Cases are unlikely to contain comprehensive details of sand control and management measures. However design safety cases should identify that the issue of produced sand has been addressed. If the design basis is for no sand production we would expect a critical review of the reservoir and completion to have been undertaken. Any contingency plans for unexpected sand production should be identified. Operations safety cases should identify wells prone to sand production and outline any sand control measures in place. Information may be provided or sought under the following Regulations.

The Safety Case Regulations (SI 1992/2885) regulation 8 (1) (c) requires an operator or owner to *include sufficient particulars to demonstrate that .all hazards with the potential to cause a major accident have been identified; and* 8 (1) (d) that *risks have been evaluated and have been, or will be, taken to reduce the risks to persons.* to ALARP.

SCR Schedule 1 para 14 for design safety cases is a general requirement to provide *a description of the principal features of the design of the installation*

SCR Schedule 2 para 6 for a fixed installation, and Schedule 3 para 5 of SCR for a mobile installation; *particulars of the plant and arrangements for the control of the operations on a well, including those - (a) to control the pressure in a well; (b) to prevent the uncontrolled release of hazardous substances*

Design and Construction Regulations (SI 1996/913) regulation 14 states; *Before the design of a well is commenced the well-operator shall cause - (a) the geological strata and formations, and fluids within them, through which it may pass; and (b) any hazards which such strata and formations may contain, to be assessed.*

PUWER Reg 5: *Ensure that work equipment is maintained in an efficient state, in efficient working and in good repair*

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