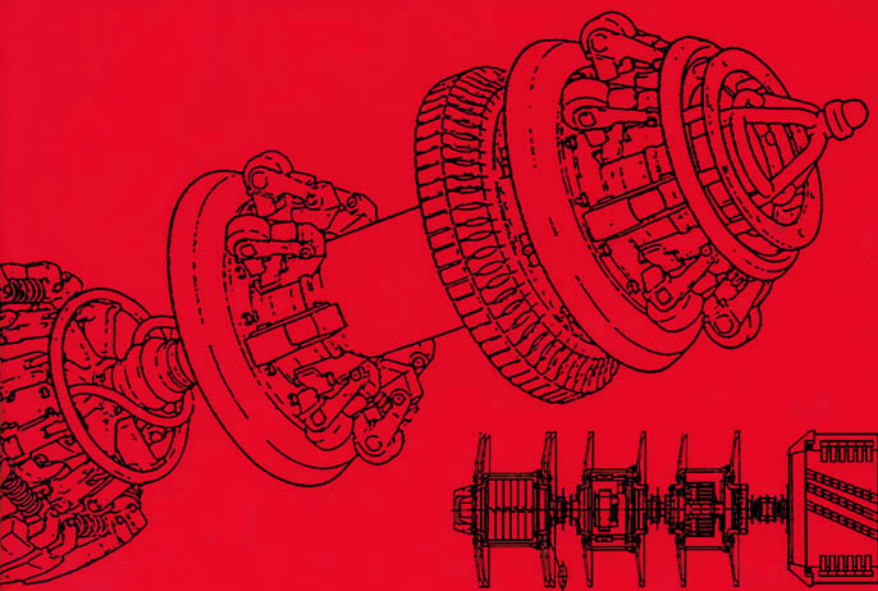


SECOND EDITION

PIPELINE PIGGING TECHNOLOGY

Cleaning • Inspection • Fitness-for-purpose



J.N.H. TIRATSOO, EDITOR

PIPELINE PIGGING TECHNOLOGY

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PIPELINE PIGGING TECHNOLOGY

2nd Edition, 1992

Edited by J.N.H. Tiratsoo
BSc, CEng, MICE, MIWES, MICorr, MIHT



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*They roll and rumble,
They turn and tumble,
As pigges do in a poke.*

Sir Thomas More, Works, 1557
How a Sergeant would learn to Play the Frere

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US3 *Pipeline pigging and inspection technology*, Houston, Feb 1991
REHAB *Pipeline risk assessment, rehabilitation and repair*,
Houston, May 1991
-

FOREWORD

THIS SECOND, completely-revised, edition of *Pipeline Pigging Technology* is essentially a compilation of selected papers presented at the conferences organized by *Pipes & Pipelines International* and *Pipe Line Industry* in the UK and the USA between 1988 and 1991. The book is thus a successor to the first edition, published in 1987, and brings readers up-to-date with the rapidly-developing technology of pipeline pigging.

Although the international pigging industry has unquestionably made major advances in its scope and expertise over the intervening years, it is nevertheless apparent that the comment made in the earlier book - that there is a general lack of knowledge about the use of pipeline pigs of all kinds - is still relevant today. Not only have the conferences at which these papers were presented produced questions such as 'How do I interpret the results of this intelligent pigging inspection?', but they also continue to produce the most basic of pigging questions such as 'Should I use discs or cups?' or 'Will foam pigs or rigid pigs work the best in this application?'.

It cannot be claimed that this book will provide readers with the answers to all their questions; indeed, many such answers remain in the experimental field of 'try it and see'. Nevertheless, we have gathered together in this edition a collection of 33 papers which give a comprehensive overview of the current situation, written by respected authors, from whom further information can undoubtedly be readily obtained by seriously-interested readers and organizations.

It is significant to note that, in early October, 1991, the first-ever major research project into the performance of 'conventional' pigs was entering its second phase. At the same time, the Pigging Products and Services Association was developing into a healthy organization with increasing membership, while the world's first long-distance gas pipeline designed with a total commitment to intelligent pigging was being constructed in the North Sea. These three discrete activities show that the hydrocarbons pipeline industry is paying increasing interest to pigging, which is seen, more-and-more widely, as an important aspect of future pipeline operations.

Readers will find in this book papers that cover subjects more diverse than simply the practicalities of pigging. I make no apology for this, as the basic requirements for pigging have now to be seen in a wider context, the boundaries of which are increasingly being set by legislation. Concepts such as 'fitness-for-purpose' and 'integrity management', the practical development of which will allow an operator to manage his pipeline with greater precision and safety, will nevertheless be based on data obtained from successful pigging operations.

On page xii will be found a list of the contributors, together with references to the conferences at which their papers were originally presented. I am greatly indebted to all these authors, both for their willingness to participate in the conferences, and for their agreement to allow their papers to be published in this book.

It should be explained that, although edited as far as possible into a uniform appearance, the papers appear here in the same form as that in which they were originally presented. Any errors are, of course, my own.

John Tiratsoo, October, 1991

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PART 1

REASONS AND REGULATIONS

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WHY PIG A PIPELINE?

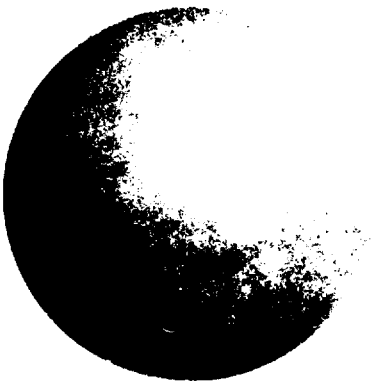
INTRODUCTION

Why pig a pipeline? This paper introduces a number of reasons for doing so, together with a discussion of the advantages and alternatives. In general terms, however, pigging is not an operation to be undertaken lightly. There are often technical problems to be resolved and the operation requires careful control and co-ordination. Even then, there is always a finite risk that a foreign body introduced into the pipeline will become lodged, block the flow and have to be cut out with all the operational expense and upset which would accompany such an incident. The pipeline operator must therefore give serious consideration to whether his line really needs to be pigged, whether it is suitable to be pigged, and whether it is economic to do so.

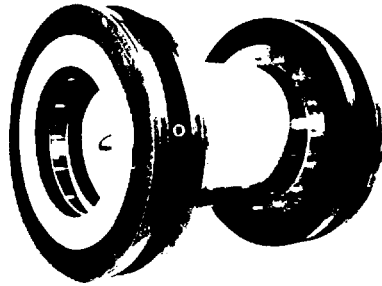
The name pig was originally applied to *Go-Devil* scrapers which were devices driven through the pipeline by the flowing fluid trailing spring-loaded rakes to scrape wax off the internal walls. The rakes made a characteristic loud squealing noise, hence the name "pig" which is now used to describe any device made to pass through a pipeline driven by the pipeline fluid.

A large variety of pigs has now evolved, some of which are illustrated in Fig.1. They typically perform the following functions:

- separation of products
- cleaning out deposits and debris
- gauging the internal bore
- location of obstructions
- meter loop calibration
- liquids' removal
- gas removal
- pipe geometry measurements
- internal inspection
- coating of internal bore
- corrosion inhibition
- improving flow efficiency



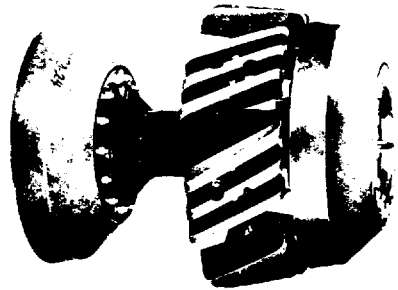
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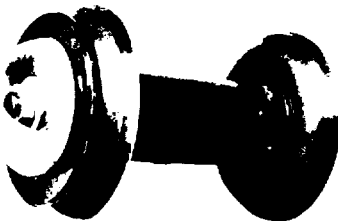
Batching pig



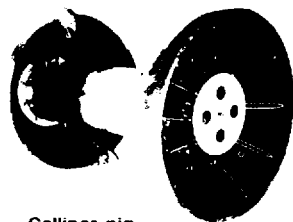
Brush pig



Scraper pig



Gauging pig



Calliper pig

Fig.1. Typical types of pig.

As new tools and techniques are developed, the above list is expanding, and has come to include self-propelled and tethered devices such as piggable barrier valves and pressure-resisting plugs.

The following paragraphs consider a pipeline from construction through to operation and maintenance, looking at possible requirements for pigging.

Why pig a pipeline?

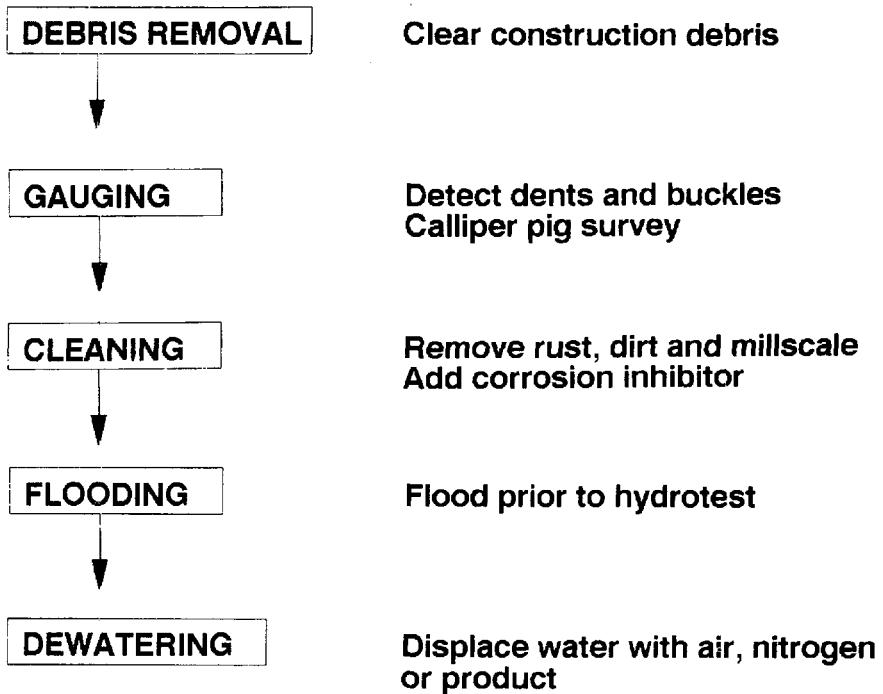


Fig.2 Pigging sequence during construction.

Examples have been chosen to illustrate each application. There will, of course, be many other variants which are covered in more specialized texts.

PIGGING DURING CONSTRUCTION

A typical sequence of events where pigs are used during pipeline construction is shown in Fig.2. The main operations are debris removal, gauging the internal bore, cleaning off dirt, rust, and millscale, flooding the line for hydrotest, and dewatering prior to commissioning.

Debris removal onshore

During onshore construction, it is quite possible for soil and construction debris to find its way inside the pipeline. Such debris could wreak havoc with

the operation of the pipeline by blocking downstream filters, damaging pump impellers, jamming valves open, and so on. In some instances the pipeline operator may reason that small amounts of debris can be tolerated, but in most cases the construction team will have to show that any debris has been removed. The only way of doing so efficiently and convincingly is to run a pig through the line.

Typically, once a section of pipeline has been completed, an air-driven pig is sent through the line to sweep out the debris. The sections are kept short so that the size of compressor and volume of compressed air are minimized.

Debris removal offshore

Offshore pipelines need to be constructed free of debris for the same reasons as onshore pipelines. Strict control of the working practices on board the lay barge minimizes the amount of debris entering the pipe in the first place. The firing-line arrangement lends itself to having a pig a short distance down inside the pipeline being pulled along by a wire attached to the barge. As the lay barge moves forward, the pig is drawn through the pipeline driving any debris before it.

Gauging

Often the landline debris-removal operation is combined with gauging to detect dents and buckles. The operation proves that the pipeline has a circular hole from one end to the other. Typically an aluminium disc with a diameter of 95% of the nominal bore is attached to the front of the pig and is inspected for marks at the end of the run. The pig would also carry a pinger emitting an audible signal, so that if a dent or buckle halted the pig the construction crew could locate it and repair the line.

Offshore, the most likely place for a buckle to develop during pipe laying is in the sag bend just before the touchdown on the seabed. To detect this, a gauging pig is pulled along behind the touchdown point. If the vessel moves forward and the pig encounters a buckle, the towing line goes taut indicating that it is necessary to retrieve and replace the affected section of line pipe.

Calliper pigging

Calliper pigs are used to measure pipe internal geometry. Typically they have an array of levers mounted in one of the cups as shown in Fig.1; the levers

Why pig a pipeline?

are connected to a recording device in the body. As the pig travels through the pipeline the deflections of the levers are recorded. The results can show up details such as girth-weld penetration, pipe ovality, and dents. The body is normally compact, about 60% of the internal diameter, which combined with flexible cups allows the pig to pass constrictions up to 15% of bore.

Calliper pigs can be used to gauge the pipeline. The ability to pass constrictions such as a dent or buckle means that the pig can be used to prove that the line is clear with minimum risk of jamming. This is particularly useful on subsea pipelines and long landlines where it would be difficult and expensive to locate a stuck pig. The results of a calliper pig run also form a baseline record for comparison with future similar surveys, as discussed further below.

Cleaning after construction

After construction, the pipeline bore typically contains dirt, rust, and millscale; for several reasons it is normal to clean these off. The most obvious of these is to prevent contamination of the product. Gas feeding into the domestic grid, for example, must not be contaminated with particulate matter, since it could block the jets in the burners downstream. A similar argument applies to most product lines, in that the fluid is devalued by contamination.

A second reason for cleaning the pipeline after construction is to allow effective use of corrosion inhibitors during commissioning and operation. If the product fluid contains corrosive components such as hydrogen sulphide or carbon dioxide, or the pipeline has to be left full of water for some time before it can be commissioned, one way of protecting against corrosive attack is by introducing inhibitors into the pipeline. These are, however, less effective where the steel surface is already corroded or covered with millscale, since the inhibitors do not come into intimate contact with the surface they are intended to protect.

Thirdly, the flow efficiency is improved by having a clean line and keeping it clean. This applies particularly to longer pipelines where the effect is more noticeable.

It will be seen from the above that most pipelines will require to be clean for commissioning. Increasingly, operators are specifying that the pipe should be sand blasted, coated with inhibitor and the ends capped after construction in order to minimize the post-construction cleaning operation. A typical cleaning operation would consist of sending through a train of pigs driven by water. The pigs would have wire brushes and would permit some by-pass flow of the water so that the rust and millscale dislodged by the

brushing would be flushed out in front of the pigs and kept in suspension by the turbulent flow. The pipeline would then be flushed and swept out by batching pigs until the particulate matter in the flow had reduced to acceptable levels. Fig.1 shows typical brush and batching pigs.

Following brushing, the longer the pipeline the longer it will take to flush and sweep out the particles to an acceptable level. Gel slugs are used to pick up the debris into suspension, clearing the pipeline more efficiently. Gels are specially-formulated viscous liquids which will wet the pipe surface, pick up and hold particles in suspension. A slug of gel would be contained between two batching pigs and would be followed by a slug of solvent to remove any traces of gel left behind.

Flooding for hydrotest

In order to demonstrate the strength and integrity of the pipeline, it is filled with water and pressure tested. The air must be removed so that the line can be pressurized efficiently as, if pockets of air remain, these will be compressed and will absorb energy. It will also take longer to bring the line up to pressure and will be more hazardous in the event of a rupture during the test. It is therefore necessary to ensure that the line is properly flooded and all the air is displaced.

A batching pig driven ahead of the water forms an efficient interface. Without a pig, in downhill portions of the line, the water would run down underneath the air trapping pockets at the high points. Even with a pig, in mountainous terrain with steep downhill slopes, the weight of water behind the pig can cause it to accelerate away leaving a low pressure zone at the hill crest. This would cause dissolved air to come out of solution and form an air lock. A pig with a high pressure drop across it would be required to prevent this.

Alternatives to using a pig include flushing out the air or installing vents at high points. For a long or large-diameter pipeline achieving sufficient flushing velocity becomes impractical. Installing vents reduces the pipeline integrity and should be avoided. So for flooding a pipeline, pigging is normally the best solution.

Dewatering and drying

After hydrotest the water is generally displaced by air, although sometimes nitrogen or the product are used. The same arguments apply to dewatering as applied to flooding. A pig is used to provide an interface between the air

Why pig a pipeline?

and the water so that the water is swept out of the low points. Sometimes a bi-directional batching pig is used to flood the line, is left during the hydrotest, and is then reversed to dewater the line.

In some cases it is necessary to dry the pipeline. This is particularly so for gas pipelines, where traces of water may combine with the gas to form hydrates, waxy solids which could block the line. Following dewatering the pipe walls will be damp, and some water may remain trapped in valves and dead legs. The latter are normally eliminated by designing dead legs to be self-draining, and by fitting drains to valves where necessary.

One way to dry the pipeline is to flush the water with methanol or glycol. The latter chemical also acts as an inhibitor, so that traces of water left behind do not form hydrates. To fill the pipeline with methanol would be prohibitively expensive; instead a slug or slugs of methanol are sent through the pipeline between batching pigs.

Vacuum drying is increasingly being used as an alternative to methanol swabbing for offshore gas lines. Here vacuum pumps reduce the internal pressure in the pipeline so that the water boils and the vapour is sucked out of the line.

PIGGING DURING OPERATION

If pigging is required during operation, then the pipeline must be designed with permanent pig traps, especially when the product is hazardous. As was mentioned above, it is far better to avoid pigging if possible, but for some operations it is the safest and most economical solution. Typical applications for pigging in operational lines are illustrated in Fig.3, and include separation of products, flow improvement, corrosion inhibition, meter proving and inspection.

Separation of products

Some applications demand that a pipeline carries a number of different products at various times. It is basically a matter of economics and operational flexibility as to whether a single line with batches of products in series is to be preferred to numerous exclusive lines where the products can flow in parallel.

As with flooding and dewatering, a batching pig provides an efficient interface between products, minimizing cross contamination. To ensure that

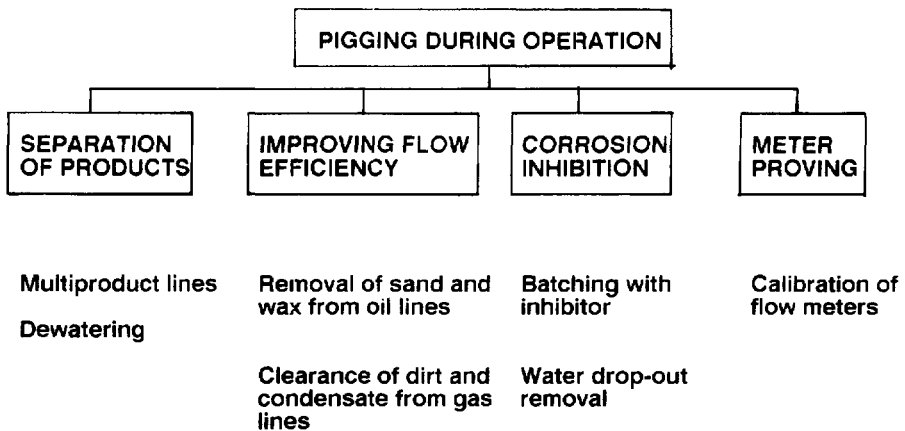


Fig.3. Pigging during operation.

no mixing takes place, a train of two or three batching pigs could be launched with the new product in between.

Wax removal

Some crude oils have a tendency to form wax as they cool. The wax crystallizes onto the pipe wall reducing the diameter and making the surface rough. Both effects reduce the flow efficiency of the pipeline such that more pumping energy must be expended to transport the same volume of oil.

A variety of cleaning and scraping pigs is available to remove the wax; most work on the principle of having a by-pass flow through the body of the pig, over the brushes or scrapers, and out to the front. This flow washes the wax away in front of the pig. The action of the pig also polishes wax remaining on the pipe wall, leaving it smooth with a low hydraulic resistance.

There are alternatives to pigging for this application. For example, it is possible to add pour-point depressants to inhibit wax formation, or it is possible to add flow improvers which reduce turbulence and increase the hydraulic efficiency of the pipeline. For a given pipeline, the choice will depend on the reduction in pumping costs against the cost of pigging or chemical injection, if indeed there is a net gain. Regular pigging does,

Why pig a pipeline?

however, have the advantage that it proves the line is clear and there is no wax build up which might cause problems for a line which is only pigged occasionally.

Line cleaning

Similar arguments about improving pumping efficiency apply to any products prone to depositing solids on the pipe wall. Gas line efficiencies can be improved by removing dust or using a smooth epoxy-painted internal surface.

Condensate clearance

In gas lines, conditions can occur where liquids condense and collect on the bottom of the pipeline. They can be swept up by the gas to arrive at the terminal in the occasional large slug, causing problems with the process facilities. Slug catchers which are basically large separators are used to absorb these fluctuations. However, it is normal to limit the potential size of the condensate slugs by regular sphering, and thus reduce the size of the slug catcher required.

Corrosion inhibition

Inhibitors are used to prevent the product attacking and corroding the pipeline steel. In some cases, particularly in liquid lines, small quantities of inhibitor are added to the flow. However, in other cases it is necessary for the inhibitor to coat the whole inside surface of the pipe at regular intervals. This is accomplished by retaining a slug of inhibitor between two batching pigs. This method also ensures that the top of the pipe is coated.

Meter proving

In order to calibrate flowmeters during operation, a pig is used to displace a precisely-known volume of fluid from a prover loop past the flowmeter. Normally a tightly-fitting sphere is used for this purpose, and the run is repeated until consistent results are obtained.

SPECIALIST APPLICATIONS

The field of pigging is expanding towards ever more sophisticated devices and specialist applications. In particular, the requirement to survey pipelines to detect not only dents and buckles, but also corrosion pitting and cracks has led to the development of intelligent pigs. Pigging systems have also evolved to satisfy other demands such as the ability to paint the internal bore, or to install a retrievable subsea safety valve similar to a down-hole safety valve, or to plug the pipeline so that maintenance can be carried out without a shut down, and so on. The following paragraphs look at these applications, which are also summarized in Fig.4.

Magnetic-flux leakage intelligent pigs

A brief mention was made above of the regular use of calliper pig surveys to detect pipeline geometry defects and compare with a baseline run during commissioning. More sophisticated techniques allow the determination of wall thickness over the entire pipe surface as well as picking up dents, buckles and pipe ovality. One such technique is magnetic-flux leakage detection.

The principle of magnetic-flux leakage detection is used to determine the volume of metal loss, and hence the size of defect. The pigs will function in both gas and liquid lines. Since the shape of the magnetic output trace has to be interpreted, the characterization is often improved by running a series of surveys over a number of years to establish trends.

The alternative to using an intelligent pig to survey the wall thickness of the line is to take ultrasonic measurements at key points along the pipeline such as bends, crossings, tees, etc. Such measurements could easily miss a problem and lead to a false sense of security; they are no match for the comprehensive information obtained via intelligent pigs, but are obviously much cheaper.

Ultrasonic intelligent pigs

Using the internal fluid as a couplant, ultrasonic pigs measure the wall thickness of the entire pipeline surface. Since it is a direct measurement of wall thickness, the interpretation is more straightforward than for a magnetic-flux pig. They are better suited to liquid lines and cannot be used in gas lines without a liquid couplant. Otherwise, the advantages over external ultrasonic scanning are the same as for the magnetic-flux pigs.

Why pig a pipeline?

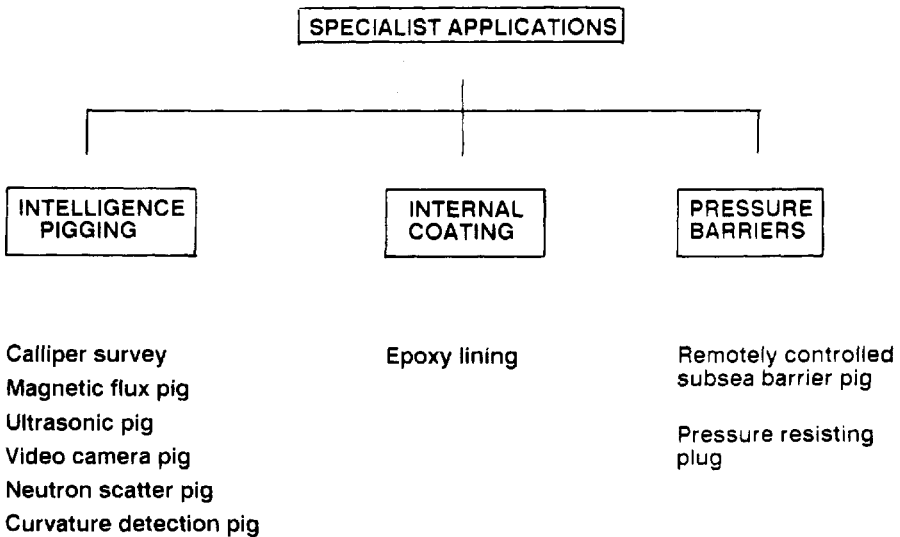


Fig.4 Specialist pigging applications.

The use of intelligent pigs comes down to an assessment of the improvement in safety and integrity of the line resulting from the detailed survey. Presently, new offshore pipelines are normally designed to handle intelligent pigs, and they are being run in the major trunk lines.

Other intelligent pigs

Several types of pig are under development. Amongst these is a neutron-scatter pig to detect spanning and burial in subsea pipelines. In places along a subsea pipeline the seabed can scour away leaving a vulnerable span. Spans are presently found by external inspection using side-scan sonar or ROVs. However, the neutron-scatter pig offers the possibility of reducing the amount of external survey required and detecting with greater accuracy the span characteristics.

Other examples include a video camera mounted on a tethered pig which has been used for the internal inspection of pipelines close to the ends, and a curvature-detection pig used to detect excessive pipeline strains due to frost heave and thaw settlement in Arctic areas.

Internal coating

It is often desirable to coat the internal surface of a pipeline with a smooth epoxy liner to give improved flow and added corrosion protection. A pigging system has been developed to achieve this by first of all cleaning the internal surface, and then pushing through a number of slugs of epoxy paint. The alternative is to pre-coat most of the pipe and leave the welds uncoated.

Pressure-resisting plug

It is sometimes desirable to carry out maintenance on a pipeline without shutting down and depressurizing it; this is particularly true of systems with many users. In cases where there are not enough isolation valves, or it is the isolation valves which are in need of repair, a pressure-resisting plug may be pigged into the line to seal off the downstream operation. Present designs are operated from an umbilical which limits their range and necessitates a special seal on the pig trap door, but a remotely-controlled plug could be developed.

Piggable barrier valve

Subsea safety valves are used to protect offshore platforms against the inventory of the pipeline in the event of a failure close to the platform; this applies particularly to the larger gas pipelines. They comprise a subsea valve, actuator, control system, umbilical and protective cover.

As a potentially-cheaper alternative, a piggable barrier valve could be used. This would be pigged into position say 500m from the platform, and remotely set in place. It would act as a non-return valve to prevent back flow of gas in the event of an upstream depressurization. Its main disadvantage would be the prevention of routine pigging.

Looking ahead, there is still a demand for improvements in pigging systems to replace techniques which are often less than ideal. One can envisage carrying out complete surveys of pipelines from the inside, monitoring wall thickness, mapping position, subsidence, spanning and burial, and detecting external damage, debris and anode wastage. One could look to the use of down-hole and nuclear-industry technologies to develop remote-controlled safety valves, repair operations, pressure-retaining plugs, and third-party tie-in operations. In this age of space travel, there is still plenty of scope to develop pigging technology to compete with more traditional techniques.

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ON-LINE INSPECTION TECHNIQUES: AVAILABLE TECHNOLOGY

IN-LINE inspection using "intelligent pigs" can now provide most, if not all, of the information required about the condition of a pipeline, enabling the operator to decide what must be done to rehabilitate it and the means thereafter to regularly examine it to ensure it remains in good condition.

This paper examines the technology which is currently available, the methods used, and provides an insight into some of the discussions which surround them.

INTRODUCTION

Although an increasing number of pipelines have already reached the end of their original design life, there is no reason why they cannot continue in service provided their integrity can be properly and regularly monitored.

Whether the concern is that of risk assessment, rehabilitation or repair, there is one fundamental requirement:

to accurately establish the present state of the pipeline.

Unless and until that is done, no decisions or plans can be made.

Clearly one of the first steps, then, is to carry out a detailed inspection programme to obtain all the necessary technical data about the condition of the pipeline. This information will be gathered from many sources, including past records, but it will inevitably involve the use of a wide range of non-destructive testing (NDT) methods.

Unlike most pressure vessels, a pipeline is usually only easily accessible at each end. Onshore pipelines are usually buried and may run under roads, rivers and railways. They may have access points at valve pits, but these may be many miles apart.

Offshore pipelines, even if they are not buried, invariably have concrete weight coatings, and may be many hundreds of feet deep.

So, whether a pipeline is onshore or offshore, the only way a complete inspection can be carried out is from inside the pipeline using "intelligent pigs". Not surprisingly, in the United States, this is usually referred to as "in-line inspection" or ILI.

Apart from the obvious advantage of being able to inspect a pipeline throughout its entire length without disturbing it, there is the added bonus of being able to do so while it remains in operation. It is for this reason that in Europe the operation is generally referred to as "on-line inspection".

AVAILABLE ILI TOOLS

The first commercially-available inspection service using ILI tools was launched some 25 years ago. Since then there has been a dramatic increase in the number of services available, and perhaps more importantly, technological development has led to extremely high levels of both accuracy and reliability.

Many of the ILI tools currently being used are primarily for operational and routine maintenance purposes; some, such as the British Gas elastic-wave pig for stress-corrosion crack detection, and its burial and coating-assessment tool, which should resolve many offshore problems, are believed to be undergoing further development. However, the following is typical of the information which can readily be provided for risk assessment, or to enable decisions to be taken concerning rehabilitation or repair:

- pipeline geometry - measuring ovality, expansion, dents, wrinkles, etc.;
- locating partially-closed valves or other restrictions;
- determining bend radii and the location of tees;
- pipeline alignment - locating and measuring movement or curvature of the line which may be due to subsidence, erosion, earthquakes, landslips, etc.;
- visual inspection - providing pictures of the internal surface of the pipeline;
- metal loss - locating and measuring any loss of pipe-wall thickness due to corrosion, gouges, or to any other cause.

Today, there are more than 30 different ILI tools in use by various manufacturers, most of whom are members of the Pigging Products &

Services Association (PPSA). PPSA is a relatively-new body which, it is hoped, will help to establish industry standards for ILI world-wide.

With the exception of one or two recent introductions, all the ILI tools currently available were described in a previous paper[1], and a list of manufacturers of each type is shown in Fig.1. Further details are also available from the PPSA.

Each of these tools is often very different, and they are so highly specialized that, without exception, they are not sold, but are used by their manufacturer to carry out the inspection on behalf of the operator.

The cost of an inspection service, therefore, also varies widely. The following figures were among the large amount of data gathered by Battelle in a study which was carried out on behalf of the American Gas Association in the mid-1980s[2]. Although there are a number of qualifications, and prices will have altered since, the basic figures serve to illustrate the wide range of costs, and variations of this order still apply today:

<i>Type of ILI tool</i>	<i>Cost (\$)/mile</i>
Geometry	100 - 200
Camera	100 - 200
Conventional metal loss	450 - 1320
Advanced metal loss	3000 - 5000

Much of this variation is due to the length of the line. Mobilization of the men and equipment will involve significant expense and so, all other things being equal, a short line will be significantly more expensive per mile than a long one. However, the cost of the technology used will probably have an even greater effect, and it is therefore important for the operator to have an appreciation of this aspect, if not a complete understanding.

CURRENT ILI TECHNOLOGY

Every conceivable method of detecting and measuring anomalies in a pipeline have been considered, and many of them have been tried. This work has been done in the manufacturers' own research establishments, as well as in laboratories and universities throughout the world.

A pipeline presents a formidable environment for what, in most cases, is very precise, "hi-tech", electronic and mechanical equipment. In a pipeline,

Pipeline Pigging Technology

SUPPLIERS OF ILI SERVICES

<u>Geometry</u>	Enduro Pipeline Services* Internal Pipeline Inspection Services Pigco Pipeline Services Pipetronix* H Rosen Engineering* Trapil Vetco Pipeline Services T D Williamson*
<u>Alignment</u>	Pigco Pipeline Services
<u>Photographic</u>	Geo Pipeline Services NKK*
<u>Metal loss (MFL)</u>	British Gas* Pipetronix* R-Con International H Rosen Engineering* Trapil Tuboscope Vetco Pipeline Services
<u>Metal loss (U/S)</u>	Advanced Monitoring Systems NKK* Pipetronix* Roentgen Technische Dienst* T D Williamson*
<u>Crack detection</u>	British Gas* Pipetronix* Roentgen Technische Dienst* H Rosen Engineering*
<u>Leak detection</u>	H Maihak Pipetronix* H Rosen Engineering*
<u>Sampling</u>	Pipetronix*
<u>Wax deposition</u>	British Gas* Pipetronix* H Rosen Engineering*
<u>Burial/Coating</u>	British Gas*

* Suppliers who are members of:

Pigging Products & Services Association
IV The Mews
Cricklade Street
Cirencester
Glos.
England
GL7 1HY

Tel: (44) (0) 285 650001
Fax: (44) (0) 285 650003

Fig.1. Suppliers of ILI services.

an ILI tool, equipped with sensors, must carry data-gathering, processing and storage equipment, as well as its own power source. It may travel hundreds of miles in perhaps crude oil, at high pressures. It will often start and end its journey via several 90° bends and a vertical riser - quite apart from the somewhat less-than-delicate manner in which it will be handled by the roustabouts...

It is not surprising, therefore, that a great many inspection techniques which work in a laboratory will not work in a pipeline. And many millions of dollars have been spent in proving this point.

We are therefore left with relatively-few techniques which are truly "tried and tested" - and even these are subjected to almost constant further development.

Geometry pigs

Electro-mechanical

The first ILI geometry tool was the TDW "Kaliper" pig (Fig.2); the early versions utilized the electro-mechanical method, as a number of other manufacturers still do today.

A series of fingers radiate from the centre of the pig. These are attached to a rod which passes through a seal into a pressure-tight chamber. Inside the chamber, a stylus mounted on the end of the rod rests on a paper chart running between two rollers. One of the rollers is driven by a stepper motor, actuated by a reed switch mounted in one (or both) of the arms, which in turn is triggered by magnets buried in the odometer wheels.

Odometer wheels are a feature of almost all ILI tools, and are machined to a diameter which gives a predetermined length of travel for each revolution (typically 1ft).

As the pig passes a reduction in diameter, the fingers are deflected. This moves the centre rod a certain distance (depending on the size of the reduction), and so marks the chart accordingly. Thus, both the extent and the location of the reduction are recorded, and can be seen on the chart when it is removed at the end of the run. Skilled interpretation of the trace can distinguish different types of reduction, such as a dent compared to ovality.

Electronic-mechanical

An obvious development of the electro-mechanical tool was to record the movement of the stylus electronically, rather than on a paper chart. The

resulting data is fed into a PC, and the results can be shown on a VDU. Hard copy can also be provided if required.

A major advantage of the electronic-mechanical method is the ability to select any particular signal, or series of signals, and enlarge them. In this way, the particular feature and its dimensions can be much more accurately determined, often without the need for input from a skilled technician.

Electro-magnetic

The pioneer in this field is H.Rosen Engineering (HRE), a highly-innovative company, who can claim a number of "firsts" in the field of ILL.

The original HRE geometry pig had strain gauges mounted around its circumference which, when deflected by a reduction, provided a signal to the on-board data processor/storage unit. It was not long, however, before HRE introduced its electro-magnetic "electronic gauging" pig or EGP (Fig.3). The dome-shaped unit on the rear generates and radiates an electro-magnetic field which, for all practical purposes, is only affected by the relative distance of any ferrous material (i.e. the pipe wall). Changes in the field due to any reductions in diameter of the pipe are converted to an electrical signal which is processed and stored on board for subsequent down-loading into a portable PC when the pig is received.

Preliminary results are available on site almost immediately, and hard copy combined with a zoom capability to match the scale of available strip maps, greatly simplifies reporting.

One major advantage of this system is that it does not require contact with the pipe wall. This not only eliminates many mechanical problems but, as it is capable of taking readings at a rate of 50 times per second, it also gives it a very wide allowable speed range and inherently-robust qualities.

The geometry readings are taken by a number of individual sensors, each being recorded on its own channel and so forming the basis for determining the radial location of any features. Distance measurement is by odometer wheel, and an additional channel provides a constant readout of the speed.

Alignment pigs

Gyroscopic

Perhaps not surprisingly, gyroscopes were among the first ideas to be tried for determining the alignment of a pipeline. Drawing on the development

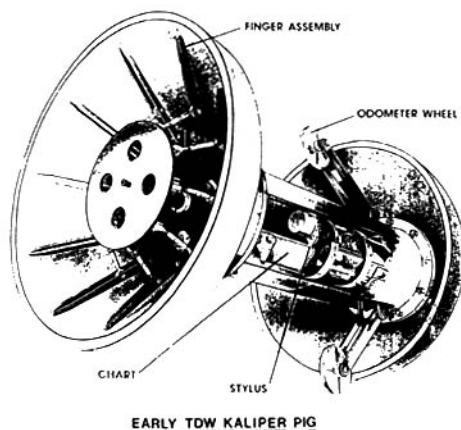


Fig 2

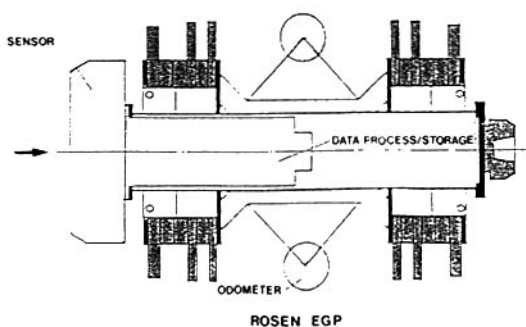


Fig 3

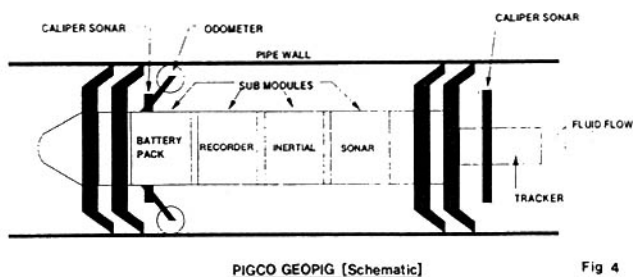


Fig 4

**Fig.2 (top). Early TDW 'Kaliper' pig.
Fig.3 (centre). Rosen 'EGP'.
Fig.4 (bottom). Pigco 'Geopig' schematic.**

work done in the aerospace industry, it is also not surprising that they have been successful in this role.

Although HRE was also one of the pioneers of this method, a lot of development has recently been done by Pigco Pipeline Services in Canada on its "Geopig" (Fig.4). As with most modern ILI tools, the technology is very advanced, and a very detailed description of the Geopig was given in a recent paper[3] (*see pages 343-364*).

The heart of the system is a "strapdown inertial measurement unit" or SIMU. This contains both accelerometers and gyros which, when coupled, provide input for computing pipeline curvature, the orientation of that curvature, and its position.

The SIMU is installed inside the pig body, which in turn is supported on elastomer drive discs. Although this ensures that the SIMU will travel in close approximation to the centreline of the pipe, it is recognized that the pig's pitch and heading will not coincide with the slope and azimuth of the pipeline. The pig is therefore fitted with a ring of sonars at each end of the inertial system, to provide constant readings of the pig-to-pipe attitude.

Odometer wheels are used for distance measurement, and the instrumentation also provides for the measurement and recording of the pipeline geometry such as diameter reductions, etc.

Large amounts of data are gathered, and it was quickly recognized that hard copy was, in effect, unmanageable. Instead, a PC software package has been developed with the data contained on an optical disc. This allows for rapid retrieval or manipulation of the information, and effectively eliminates errors in interpretation.

Visual inspection

Photographic

The results obtained by some of the early ILI tools were often (and with some justification) regarded with scepticism, and it was felt that visual confirmation of a particular feature would be helpful. However, pictures can only be obtained in good visibility, which limits the use of this technique to relatively-clean, clear gas or liquids. In addition, the information provided by ILI tools quickly became more detailed and reliable, so there was no need for visual inspection to confirm the results. These factors combined to limit the use of visual inspection.

There are still, though, many situations where a visual inspection can be very useful. One area in particular is for inspecting the condition of linings,

especially if they have been applied *in situ*.

One camera pig operated by Geo Pipeline Services utilized a 35-mm camera with a strobe light and wide-angle lens. The camera is mounted at right angles to the pipe wall, and can be rotated to focus on any part of the circumference. The instrumentation contains distance measurement, so that the location of the photograph can be accurately determined.

A more recent development by NKK (Fig. 5) has a different basic design, in that the camera is mounted in the rear of the pig, providing a photograph looking down the length of the pipe. It can be set to take photographs at pre-determined intervals, or it can be fitted with a detector for girth welds, which it automatically photographs once it has passed by. It, too, is particularly useful for the inspection of *in situ* coatings.

It is capable of taking a large number of photographs in a single run. On one run, for example, a 24-in (nom.) is understood to have covered a distance of 20km, and taken 13,000 photographs.

Video recording

Although there are a number of crawler-type devices attached to umbilicals for the video inspection of short sections of pipe (often water mains), there are no known ILI tools which are similarly equipped.

Metal loss

Metal loss and cracking are generally agreed to be the areas of most concern[2], and most of the money spent to date on ILI research and development has been spent in these areas.

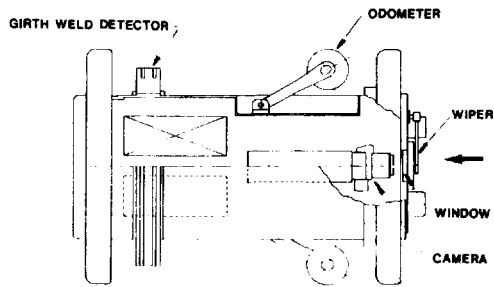
Two technologies have emerged as the preferred methods for the detection and measurement of metal loss:

magnetic-flux leakage (MFL), and
ultrasonics (U/S).

As with most technology, the basic principles are very simple. The trick is putting them into practice...

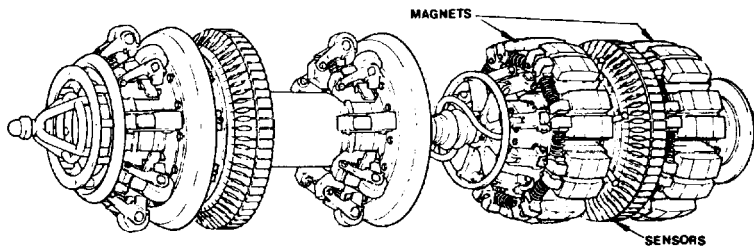
Magnetic-flux leakage (MFL)

The simplest explanation of the principle of the MFL tools can perhaps best be achieved by comparing it to the well-known horseshoe-shaped



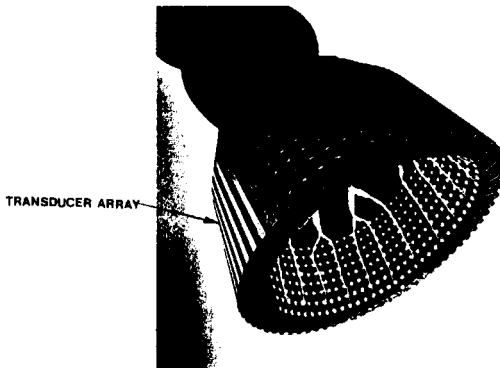
NKK CAMERA PIG

Fig 5



BRITISH GAS MFL TOOL [Typical]

Fig 6



PIPETRONIX ULTRASCAN

Fig 7

**Fig.5 (top). NKK camera pig.
Fig.6 (centre). British Gas MFL tool (typical schematic).
Fig.7 (bottom). Pipetronix 'UltraScan'.**

magnet (Fig.6). To retain its power, the magnet is fitted with a "keeper". This is simply a metal bar which carries the flux from one pole to the other. If the cross-sectional area of the keeper at any point is insufficient to contain the flux, then leakage will occur.

Similarly, the MFL ILI tools use magnets to induce a flux into the pipe wall (Fig.7). Sensors are mounted between the "poles" to detect any leakage which occurs due to thinning, or "metal loss".

Clearly it is important to induce a sufficient flux density into the pipe wall, and this requires very powerful, and often fairly-large, magnets. This has proven to be a limiting factor with respect to the use of MFL in heavy-wall pipe, as well as to the development of the smaller-size tools.

The early MFL tools suffered particularly from the lack of suitably-powerful magnets. To deal with this problem, Tuboscope, who introduced the first commercial ILI tool in 1967, chose to utilize electro-magnets. All other MFL tools have since resorted to permanent magnets, and it is here that one of the most significant developments has taken place.

British Gas, who developed what is now generally regarded as a second-generation or 'advanced' ILI tool, commented in a recent paper[4] that one of the greatest benefits during the latter stages of its development programme came from the improvements in magnetic materials. For example, Neodymium-Iron-Boron magnets have ten times the strength in energy per unit volume than the *Alcomax* magnets used in the early 1970s.

Another development which has contributed to the success of the British Gas tool is the design of the sensor system. Early sensor designs tended to be very large, giving rise to loss of contact with the pipe wall under various dynamic and geometric conditions. This particularly affected inspection in the girth weld area. The current system is now so sophisticated that metal loss in the weld itself can be detected. It can also determine whether the loss is internal or external, and can be adapted to determine absolute wall thickness if required.

British Gas once described the rate of data gathering as being equivalent to reading the Bible every six seconds. At the end of a run which may last many hours there is obviously a vast amount of data to be analyzed. The accurate identification, sizing and location of defects is fundamental requirement, but it is also important to ensure that the information is presented to the operator in an understandable and usable format. Not surprisingly, therefore, a great deal of work has gone into this aspect as well.

It is probably true to say that the successful development and introduction of the advanced MFL tool has contributed more to the industry's acceptance of ILI as a reliable method of inspection than any other single factor.

Ultrasonics (U/S)

The principle of ultrasonic inspection is also very simple. A transducer emits a pulse which travels at a known speed. On entering the pipe wall, there is an echo, and another as the pulse reflects off the back wall. The time taken for these echoes to return provides a virtually-direct reading of the wall thickness.

Again, although the principle is very simple, it too has some drawbacks. The first, and arguably the most important, is that the sound will only travel through a homogeneous liquid. The word "homogeneous" is almost as important as the word "liquid" in this context, as such things as gas bubbles and wax flocculation can affect the results.

Another important point for the ILI tool designer to keep in mind is that the transducers must be maintained square to the surface of the pipe wall to within a very few degrees, or the echo will be missed. This poses particular problems on bends.

Pipetronix has carried out a great deal of development work in order to introduce its "UltraScan" tool (*see pages 335-342*). There is less information available as to precisely what these developments are, but clearly they are significant - because they work!

Although the internals may remain a mystery, the most prominent external feature is the transducer array at the rear (Fig.8). It is also probably the most important development to date. The distance from the transducer to the pipe wall is called the 'stand-off'. Most manufacturers, notably NKK, TDW and AMS, use a stand-off of more than one inch (25mm), but Pipetronix has embedded the transducers into a polyurethane cage which is towed behind the pig. The cage flexes, maintaining the transducers in a close and constant relationship with the pipe wall, even when passing through bends or reductions in diameter. This also presumably makes it less susceptible to changes in the homogeneity of the liquid in which it is immersed.

There is a constant search for new methods and materials to further improve or expand the various ILI services, especially in the field of metal-loss detection and measurement. A typical example is in extending the use of U/S tools to gas lines. This has now been achieved very successfully on a number of occasions by running two conventional pigs in the line at either end of a slug of liquid (usually a gel) in which the U/S tool travels.

WHICH TECHNOLOGY IS BEST?

The answer to this question has to be the same as it is for every other industry when trying to select the best method for doing anything involving an advanced technology:

“It depends....”

Most of the controversy has been concerned with the relative merits of the advanced MFL and U/S tools as each vies with the other to gain a larger share of the market. This competitiveness is certainly in the interests of the operator, as it constantly drives the technology forward. However, the rate of change makes open discussion of the subject somewhat risky, even for those actively engaged in the development work, let alone for an impartial observer...

By way of example, a paper presented by de Raad in 1986[5] gave a detailed comparison between MFL and U/S tools. Many of the points he made were subsequently refuted in a paper by Braithwaite and Morgan[6] less than 18 months later.

There are one or two misconceptions which can, however, be removed:

- advanced MFL is (essentially) not influenced by speed;
- U/S tools are only influenced by speed to the extent that the impulse frequency is fixed, so the speed will determine the distance between readings;
- advanced MFL is not affected by changes in wall thickness;
- advanced MFL has limitations in the heavier wall thicknesses;
- U/S has limitations in the lighter wall thicknesses.

Often the decision is made by asking the simple questions:

- Am I prepared to have a liquid in my gas line?
- Are the traps long enough to house the pig?
- Is there a pig to suit the size of my line?

When there is no obvious answer, call in the suppliers - and talk to other operators who have recent experience. There are plenty who have past

experience, but if it is not less than, say, two years old, it is probably worthless and could be totally misleading - because this industry is on the move, constantly....

Time and tide and ILI wait for no man!

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US GOVERNMENT PIPELINE SAFETY REGULATIONS:

Regulations update and report on the regulatory posture and activities of Congress and OPS

INTRODUCTION

The Federal Regulatory picture becomes more complex as time passes. The Congress is requiring that more and more areas of safety be addressed, either by way of studies and evaluation or regulations. The OPS seems to be bogging down under the load and regulatory system. When OPS was established in 1968, a regulation normally took about 9 months to a year from notice to final rule. The entire basic set of Natural Gas Pipeline Safety Regulations was developed and published in less than two years. Today, there are proposed regulations on the agenda that have been in the process since early 1987 and early 1989, and the NPRM has not even been published. It is unfortunate, but the "system" seems not to be working, at least not working well.

This presentation will review the posture of the Congress regarding pipeline safety, with past and pending activities; OPS regulatory activities; and what the future holds, including certain areas of new and existing technology. I'll focus primarily on those areas that will impact on/or relate to the evaluation and operation of existing pipeline systems.

CONGRESSIONAL POSTURE

The Congress passed the comprehensive Pipeline Safety Reauthorization Act of 1988 that spelled out some very definite areas of concern over the safety of gas and hazardous liquid pipelines. This included the mandating of specific regulations and studies.

Pipeline Pigging Technology

During 1990, Congress held hearings on offshore pipeline navigational hazards and passed HR 4888, a bill requiring the OPS to establish regulations that will require an initial inspection for cover of gas and hazardous liquid pipelines in the Gulf of Mexico from the shoreline to the 15ft depth. Based on the findings of the study, the OPS is also directed to develop standards that will require the pipeline operators to report pipeline facilities that are hazardous to navigation, the marking of such hazards, and establish a mandatory, systematic, and where appropriate, periodic inspection programme.

This legislation involves an estimated 1400 miles of pipeline, or about 10% of the total pipelines in the Gulf of Mexico. The legislation will eventually have an impact on all gas and hazardous liquid pipelines in all navigable waters of the US, particularly those in populated and environmentally-sensitive areas.

Congressional committees are now drafting legislation for 1991 which will be included in the "Pipeline Safety Reauthorization Act of 1991". It is felt that this legislation will, in addition to underwater and offshore pipelines, include such areas as:

- (a) *Environmentally-sensitive and high-density populated areas* - require the DOT to identify all pipelines that are at river crossings, located in environmentally-sensitive areas, located in wetlands, or located in high-density population areas.
- (b) *Smart pigs* - require pipeline operators to inspect with smart pigs all lines that have been identified in (a) above. If the pipeline will not accept a pig, then the operators will have to modify the pipeline and run the pig under another set of rules. Also, there may be government funding to assist in the development of a smart pig capable of detecting potential longitudinal seam failures in ERW pipe.
- (c) *Environmental protection* - establish an additional objective of the Pipeline Safety Acts to protect the environment. This could include increasing the membership of the Technical Pipeline Safety Standards Committees to include representatives from the environmental community.
- (d) *Enforcement activities* - increase the requirements and staff of OPS to provide a more comprehensive inspection and enforcement programme.
- (e) *Operator training* - mandate requirements for programmes to train all pipeline operators/dispatchers.

US Government safety regulation

- (f) *Leak detection* - require that operators have some type of leak detection capability to detect and locate leaks in a reasonable length of time and shut the system down with minimum loss of product.
- (g) *Pipeline safety policy* - require that OPS establish a policy development group within its office.

As you can see, the Congress is becoming more involved in pipeline safety matters and will be issuing more mandates for specific regulatory requirements.

DOT/OPS REGULATORY ACTIVITIES

The DOT/OPS continues to address pipeline safety problems in its regulatory activities. Their latest regulatory agenda, published on 29th October, 1990, contained 18 rulemaking items. Of these, there are eight that I consider will have an impact on the activities of this group. A summary and the status of each are as follows:

OPS Regulatory Agenda: Proposed Rule stage

1. Hydrostatic testing of certain hazardous liquid pipelines (49 CFR 195)

SUMMARY: This rule would extend the requirement to operate all hazardous liquid pipelines to not more than 80% of a prior test or operating pressure. This proposal is based on the fact that significant results have been achieved by imposing such operating restrictions on pipelines that carry highly-volatile liquids. This rule making is significant, because of substantial public interest.

STATUS: NPRM issued 1/01/91

2. Gas-gathering line definition (49 CFR 192.3)

SUMMARY: The existing definition of "gathering line" would be clearly defined to eliminate confusion in distinguishing these pipelines from trans-

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mission lines in rural areas. Action is significant because the definition is the subject of litigation.

STATUS: NPRM to be issued early 1991.

3. Gas pipelines operating above 72% of specified minimum yield strength (49 CFR 192)

SUMMARY: This proposal would eliminate or qualify the "grandfather clause" if the natural gas pipeline safety regulations that permit operation of an existing rural or offshore gas pipeline found to be in satisfactory condition at the highest actual operating pressure to which the segment was subjected during the five years preceding 1st July, 1970, or, in the case of an offshore gathering line, 1st July, 1976.

STATUS: ANPRM issued 3/12/90

NPRM to be issued early 1991

4. Transportation of hydrogen sulphide by pipeline (49 CFR 192)

SUMMARY: This action examines the need to establish a maximum allowable concentration of hydrogen sulphide that can be introduced into natural gas pipelines and how to control it.

STATUS: ANPRM issued 9/05/90

NPRM to be issued early 1991

5. Passage of internal inspection devices (49 CFR 192; 49 CFR 195)

SUMMARY: This rulemaking would establish minimum Federal safety standards requiring that new and replacement gas transmission and hazardous liquid pipelines be designed and constructed to accommodate the passage of internal inspection devices. This rulemaking was mandated by P.L. 100-561.

STATUS: NPRM to be issued by early 1991

US Government safety regulation

6. Transportation of a hazardous liquid at 20% or less of specified minimum yield strength (49 CFR 195)

SUMMARY: This rulemaking action would assess the need to extend the Federal safety standards to cover these lower stress level pipelines (except gathering lines), and if warranted, apply the standards to those pipelines.

STATUS: ANPRM issued 10/31/90

7. Burial of offshore pipelines (49 CFR 192; 49 CFR 195)

SUMMARY: This rulemaking will propose that operators remove abandoned lines in water less than 15ft deep, bury pipelines at least 3ft deep in water up to 15ft deep, and monitor the depth of buried pipelines in water less than 15ft deep.

STATUS: NPRM to be issued 4/00/91

OPS Regulatory Agenda: Final Rule stage

8. Determining the extent of corrosion on exposed gas pipelines (49 CFR 192)

SUMMARY: This action proposed that when gas pipelines are exposed for any reason, and they have evidence of harmful corrosion, that it be investigated to determine the extent of the corrosion.

STATUS: NPRM issued 9/25/89

Final Action by early 1991.

There are two other major issues that were required by the Reauthorization Act of 1988 to be addressed by OPS: the internal inspections of pipelines, and emergency flow-restricting devices. The studies required have been completed, but as of this writing have not been provided to Congress. The Internal Inspection Report was due to Congress in April of 1990 and the Emergency Flow Restriction Device was due on 31st October, 1989.

MAJOR PIPELINE SAFETY ISSUES

1. The areas of concern continue, as in recent years, to include the following:

The evaluation of the condition and integrity of existing pipeline systems continues to be a major concern. As mentioned earlier, the pressure will continue on the OPS and industry to develop and use better methods and materials to ensure the integrity of older pipeline systems.

The internal inspection (pigging) industry is establishing itself as a unified body that can speak with authority.

2. Pipeline rehabilitation: The pipeline and service industries are teaming up to do research and develop procedures and techniques to be used in the rehabilitation of existing pipeline systems. The mileage of rehabilitation work planned or underway has increased dramatically over the past year.

3. Underwater pipelines and offshore operations: The passage of HR 4888 regarding the inspection of certain offshore pipelines just scratches the surface on requirements for underwater pipelines. The Congress will continue to push these requirements for all underwater pipelines. The inspection and survey industries will have to develop new technology and techniques to locate and determine the cover condition of these systems. The entire area of offshore pipeline operation and maintenance is undergoing a thorough review.

4. Handling of emergencies: This subject continues to be of high interest. We will see continued effort on requiring training of pipeline operators, providing equipment to detect, locate and shut down systems. Also, emphasis will be stressed on valving design and maintenance.

CONCLUSION

As you can see, the challenges of pipeline safety continue. During this year's legislative and regulatory activities there will be substantial opportunity for the pipeline and related industries to provide input to the process. With the nation's natural gas and hazardous liquid pipeline systems growing older each day, innovative techniques and equipment are going to have to be put into use. This will require the efforts of each of us, and hopefully reward all of us.

Let's strive to make regulations that solve problems, not compound existing problems or create new problems.

US FEDERAL PIPELINE SAFETY REGULATIONS: Compliance during and after rehabilitation

INTRODUCTION

As more and more emphasis is being placed on the safety of existing pipelines, rehabilitation of these systems has moved to the top of many of the gas and hazardous liquid pipeline operator's agendas. The areas of concern cover public safety and protection of the environment from pollution.

The Congress continues to demand an expansion of the pipeline safety regulatory programme in this area of pipeline integrity. If there is any question as to the direction, one only has to look at the Pipeline Safety Act of 1991 (HR 1489) now working its way through the Congress, thus placing more regulatory action on the DOT/OPS.

PIPELINE SAFETY REGULATIONS

The regulations impacting on pipeline safety are: 49CFR part 191 - *Transportation of Natural and other Gas by Pipeline; Annual Reports, Incident Reports and Safety Related Condition Reports*, 49CFR Part 192 - *Transportation of Natural and other Gas by Pipeline; Minimum Federal Safety Standards*, 49CFR Part 195 - *Transportation of Hazardous Liquids by Pipeline*; and 49CFR Part 199 - *Drug Testing*. These regulations do not specifically address rehabilitation; however, the overall requirements do cover all aspects of rehabilitation, one way or other, depending upon the work and activities selected by the operator.

As background, let's look at the several terms used in the regulations with some basic dictionary definitions:

Pipeline Pigging Technology

Construction - "the way something is put together" or "the act of putting something together";

Maintenance - "the work of keeping something in proper condition";

Move - "to change in position from one point to another";

Relocate - "to establish in a new place".

Now comes the term Rehabilitation, which means "to restore".

The purpose of this is to show that since the pipeline safety regulations do not speak to rehabilitation, *per se*, there is a lot of room for 'creative interpretation' regarding which regulations apply to what activities. This presentation is not an attempt to offer an interpretation of the regulations, but to highlight some points that I consider worth giving careful consideration to when planning and executing rehabilitation work. With more emphasis being placed on regulatory inspection and enforcement, thorough planning now could pay dividends in the future.

REHABILITATION

A rehab job is basically a large maintenance project with varying degrees of complexity that can involve several aspects of the regulations, including materials, design, general construction, welding, corrosion control, testing and operations.

There are several reasons for deciding to rehabilitate a pipeline; however, the most common is external corrosion due to coating failure. The decision to rehabilitate is usually determined by several factors, including failure history, excessive maintenance and cathodic protection costs, and, in some cases, the presence of stress-corrosion cracking. The primary motivating factor behind this decision is to maintain and operate a safe pipeline.

When planning rehabilitation work, no two jobs will be exactly alike or present the same set of circumstances. Therefore, in order to stress the importance and complexity of complying with the present Federal Pipeline Safety Standards, I have taken two projects that represent probably the most common types of work and will explore where each type method could be impacted by the regulations. The first (Method 1) is the rehab of a line that is left in place in the ditch and remains in service. The second, (Method 2) is when the line is taken out of service, evacuated, removed from the ditch and placed on skids along side the ditch.

Regulations: during and after rehabilitation

Method 1: This type can range from exposing the pipe in a bellhole of a few feet in length to a fairly long segment of several hundred feet. It is obvious that on any segment that exceeds the maximum-allowable length for unsupported line, pipe will have to be supported by either an earth plug or a temporary pipe support. Also, the situation becomes more critical on a line containing liquid. This is where the services of a very experienced stress engineer are essential.

Method 2: This type of project usually involves several miles of pipe and, by the magnitude of the job, involves a wide range of the regulations, both for gas and liquid lines. For example, some typical steps are:

1. remove the line from service and evacuate the product. (If stress-corrosion cracking is suspected, then a hydrostatic test is performed);
2. excavate the line and place on skids;
3. remove the deteriorated coating;
4. inspect the pipe surface for corrosion and damage;
5. replace all failed or damaged pipe;
6. prepare the surface and recoat the pipe;
7. place the pipe in the ditch;
8. backfill;
9. hydrostatic test;
10. tie-in and bring back into service; and
11. install cathodic-protection system.

In this type situation you have, in effect, the same circumstances as the construction of a new system.

BASIC REGULATORY AREAS CONSIDERED

Let's look at some basic areas of the pipeline regulations that have to be addressed, and briefly comment on each one; Figs 1 through 4 indicate those parts of the respective regulations that could apply to either or both methods.

The basic areas are:

U. S. FEDERAL PIPELINE SAFETY REGULATIONS

FIGURE 1

METHOD		
1	2	
		PART 191—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: ANNUAL REPORTS, INCIDENT REPORTS, AND SAFETY-RELATED CONDITION REPORTS
		Sec.
		191.1 Scope.
		191.3 Definitions.
		191.5 Telephonic notice of certain incidents.
		191.7 Addressee for written reports.
		191.9 Distribution system: Incident report.
		191.11 Distribution system: Annual report.
		191.13 Distribution systems reporting transmission pipelines; transmission or gathering systems reporting distribution pipelines.
		191.15 Transmission and gathering systems: Incident report.
		191.17 Transmission and gathering systems: Annual report.
		191.19 Report forms.
		191.21 OMB control number assigned to information collection.
		191.23 Reporting safety-related conditions.
		191.25 Filing safety-related condition reports.
		AUTHORITY: 49 App. U.S.C. 1681(b) and 1688(b); §§ 191.23 and 191.25 also issued under 49 App. U.S.C. 1672(a); and 49 CFR 1.53.

FIGURE 2

METHOD		
1	2	
		PART 192—TRANSPORTATION OF NATURAL AND OTHER GAS BY PIPELINE: MINIMUM FEDERAL SAFETY STANDARDS
		Subpart A—General
		Sec.
		192.1 Scope of part.
		192.3 Definitions.
		192.5 Class locations.
		192.7 Incorporation by reference.
		192.9 Gathering lines.
		192.11 Petroleum gas systems.
		192.13 General.
		192.14 Conversion to service subject to this part.
		192.15 Rules of regulatory construction.
		Subpart B—Materials
		192.51 Scope.
		192.53 General.
		192.55 Steel pipe.
		192.57 (Reserved)
		192.59 Plastic pipe.
		192.61 (Reserved)
		192.63 Marking of materials.
		192.65 Transportation of pipe.

METHOD		
1	2	
		Subpart C—Pipe Design
		192.101 Scope.
		192.103 General.
		192.105 Design formula for steel pipe.
		192.107 Yield strength (<i>S</i>) for steel pipe.
		192.109 Nominal wall thickness (<i>t</i>) for steel pipe.
		192.111 Design factor (<i>F</i>) for steel pipe.
		192.113 Longitudinal joint factor (<i>E</i>) for steel pipe.
		192.115 Temperature derating factor (<i>T</i>) for steel pipe.
		192.117 (Reserved)
		192.119 (Reserved)
		192.121 Design of plastic pipe.
		192.123 Design limitations for plastic pipe.
		192.125 Design of copper pipe.
		Subpart D—Design of Pipeline Components
		192.141 Scope.
		192.143 General requirements.
		192.144 Qualifying metallic components.
		192.145 Valves.
		192.147 Flanges and flange accessories.
		192.149 Standard fittings.
		192.151 Tapping.
		192.153 Components fabricated by welding.
		192.155 Welded branch connections.
		192.157 Extruded outlets.
		192.159 Flexibility.
		192.161 Supports and anchors.
		192.163 Compressor stations: Design and construction.
		192.165 Compressor stations: Liquid removal.
		192.167 Compressor stations: Emergency shutdown.
		192.169 Compressor stations: Pressure limiting devices.
		192.171 Compressor stations: Additional safety equipment.
		192.173 Compressor stations: Ventilation.
		192.175 Pipe-type and bottle-type holders.
		192.177 Additional provisions for bottle-type holders.
		192.179 Transmission line valves.
		192.181 Distribution line valves.
		192.183 Vaults: Structural design requirements.
		192.185 Vaults: Accessibility.
		192.187 Vaults: Sealing, venting, and ventilation.
		192.189 Vaults: Drainage and waterproofing.
		192.191 Design pressure of plastic fittings.
		192.193 Valve installation in plastic pipe.
		192.195 Protection against accidental overpressuring.
		192.197 Control of the pressure of gas delivered from high-pressure distribution systems.
		192.199 Requirements for design of pressure relief and limiting devices.
		192.201 Required capacity of pressure relieving and limiting stations.
		192.203 Instrument, control, and sampling pipe and components.

Fig.1 and Fig.2.

U.S. FEDERAL PIPELINE SAFETY REGULATIONS

METHOD			METHOD		
1	2		1	2	
		Subpart E—Welding of Steel in Pipelines			Subpart I—Requirements for Corrosion Control
		192.221 Scope.			192.451 Scope.
		192.225 Welding—General.			192.452 Applicability to converted pipe-
		192.237 Qualification of welders.			lines.
		192.239 Limitations on welders.			192.453 General.
		192.231 Protection from weather.			192.455 External corrosion control: Buried
		192.233 Miter joints.			or submerged pipelines installed after
		192.235 Preparation for welding.			July 31, 1971.
		192.241 Inspection and test of welds.			192.457 External corrosion control: Buried
		192.243 Nondestructive testing.			or submerged pipelines installed before
		192.245 Repair or removal of defects.			August 1, 1971.
		Subpart F—Joining of Materials Other Than by			192.459 External corrosion control: Exami-
		Welding			nation of buried pipeline when exposed.
		192.271 Scope.			192.461 External corrosion control: Protec-
		192.273 General.			tive coating.
		192.275 (Reserved)			192.463 External corrosion control: Ca-
		192.277 Ductile iron pipe.			thodic protection.
		192.279 Copper pipe.			192.465 External corrosion control: Moni-
		192.281 Plastic pipe.			toring.
		192.283 Plastic pipe; qualifying joining pro-			192.467 External corrosion control: Electr-
		cedures.			ical isolation.
		192.285 Plastic pipe; qualifying persons to			192.469 External corrosion control: Test
		make joints.			stations.
		192.287 Plastic pipe; inspection of joints.			192.471 External corrosion control: Test
		Subpart G—General Construction Requirements			leads.
		for Transmission Lines and Mains			192.473 External corrosion control: Inter-
		192.301 Scope.			ference currents.
		192.303 Compliance with specifications or			192.475 Internal corrosion control: Gener-
		standards.			al.
		192.305 Inspection: General.			192.477 Internal corrosion control: Moni-
		192.307 Inspection of materials.			toring.
		192.309 Repair of steel pipe.			192.479 Atmospheric corrosion control:
		192.311 Repair of plastic pipe.			General.
		192.313 Bends and elbows.			192.481 Atmospheric corrosion control:
		192.315 Wrinkle bends in steel pipe.			Monitoring.
		192.317 Protection from hazards.			192.483 Remedial measures: General.
		192.319 Installation of pipe in a ditch.			192.485 Remedial measures: Transmission
		192.321 Installation of plastic pipe.			lines.
		192.323 Casing.			192.487 Remedial measures: Distribution
		192.325 Underground clearance.			lines other than cast iron or ductile iron
		192.327 Cover.			lines.
		Subpart H—Customer Meters, Service			192.489 Remedial measures: Cast iron and
		Regulators, and Service Lines			ductile iron pipelines.
		192.351 Scope.			192.491 Corrosion control records.
		192.353 Customer meters and regulators:			Subpart J—Test Requirements
		Location.			192.501 Scope.
		192.355 Customer meters and regulators:			192.503 General requirements.
		Protection from damage.			192.505 Strength test requirements for
		192.357 Customer meters and regulators:			steel pipeline to operate at a hoop stress
		Installation.			of 30 percent or more of SMYS.
		192.359 Customer meter installations: Op-			192.507 Test requirements for pipelines to
		erating pressure.			operate at a hoop stress less than 30 per-
		192.361 Service lines: Installation.			cent of SMYS and at or above 100 p.s.i.g.
		192.363 Service lines: Valve requirements.			192.509 Test requirements for pipelines to
		192.365 Service lines: Location of valves.			operate below 100 p.s.i.g.
		192.367 Service lines: General require-			192.511 Test requirements for service lines.
		ments for connections to main piping.			192.513 Test requirements for plastic pipe-
		192.369 Service lines: Connections to cast			lines.
		iron or ductile iron mains.			192.515 Environmental protection and
		192.371 Service lines: Steel.			safety requirements.
		192.373 Service lines: Cast iron and ductile			192.517 Records.
		iron.			
		192.375 Service lines: Plastic.			
		192.377 Service lines: Copper.			
		192.379 New service lines not in use.			

Fig.2 (continued).

Regulations: during and after rehabilitation

U. S. FEDERAL PIPELINE SAFETY REGULATIONS

METHOD			METHOD		
1	2		1	2	
		Subpart B—Reporting Accidents and Safety-Related Conditions			
		195.50 Reporting accidents.			195.260 Valves: Location.
		195.52 Telephonic notice of certain accidents.			195.262 Pumping equipment.
		195.54 Accident reports.			195.264 Above ground breakout tanks.
		195.56 Reporting safety-related conditions.			195.266 Construction records.
		195.56 Filing safety-related condition reports.			
		195.58 Addressee for written reports.			Subpart E—Hydrostatic Testing
		195.60 Operator assistance in investigation.			195.300 Scope.
		195.62 Supplies of accident report DOT Form 7000-1.			195.302 General requirements.
		195.63 OMB control number assigned to information collection.			195.304 Testing of components.
					195.306 Test medium.
					195.308 Testing of tie-ins.
					195.310 Records.
		Subpart C—Design Requirements			
		195.100 Scope.			Subpart F—Operation and Maintenance
		195.101 Qualifying metallic components other than pipe.			195.400 Scope.
		195.102 Design temperature.			195.401 General requirements.
		195.104 Variations in pressure.			195.402 Procedural manual for operations, maintenance, and emergencies.
		195.106 Internal design pressure.			195.403 Training.
		195.108 External pressure.			195.404 Maps and records.
		195.110 External loads.			195.406 Maximum operating pressure.
		195.112 New pipe.			195.408 Communications.
		195.114 Used pipe.			195.410 Line markers.
		195.116 Valves.			195.412 Inspection of rights-of-way and crossings under navigable waters.
		195.118 Fittings.			195.414 Cathodic protection.
		195.120 Changes in direction: Provision for internal passage.			195.416 External corrosion control.
		195.122 Fabricated branch connections.			195.418 Internal corrosion control.
		195.124 Closures.			195.420 Valve maintenance.
		195.126 Flange connection.			195.422 Pipeline repairs.
		195.128 Station piping.			195.424 Pipe movement.
		195.130 Fabricated assemblies.			195.426 Scraper and sphere facilities.
		195.132 Above ground breakout tanks.			195.428 Overpressure safety devices.
					195.430 Firefighting equipment.
		Subpart D—Construction			195.432 Breakout tanks.
		195.200 Scope.			195.434 Signs.
		195.202 Compliance with specifications or standards.			195.436 Security of facilities.
		195.204 Inspection—general.			195.438 Smoking or open flames.
		195.206 Material inspection.			195.440 Public education.
		195.208 Welding of supports and braces.			
		195.210 Pipeline location.			APPENDIX A—DELINEATION BETWEEN FEDERAL AND STATE JURISDICTION—STATEMENT OF AGENCY POLICY AND INTERPRETATION
		195.212 Bending of pipe.			AUTHORITY: 49 App. U.S.C. 2002; and 49 CFR 1.53.
		195.214 Welding: General.			
		195.216 Welding: Miter joints.			
		195.222 Welders: Qualification of welders.			
		195.224 Welding: Weather.			
		195.226 Welding: Arc burns.			
		195.228 Welds and welding inspection: Standards of acceptability.			
		195.230 Welds: Repair or removal of defects.			
		195.234 Welds: Nondestructive testing.			
		195.236 External corrosion protection.			
		195.238 External coating.			
		195.242 Cathodic protection system.			
		195.244 Test leads.			
		195.246 Installation of pipe in a ditch.			
		195.248 Cover over buried pipeline.			
		195.250 Clearance between pipe and underground structures.			
		195.252 Backfilling.			
		195.254 Above ground components.			
		195.256 Crossing of railroads and highways.			
		195.258 Valves: General.			

Fig.3 (continued) and Fig.4.

Pipeline Pigging Technology

Materials

Any materials or components, whether new or used, that are added to the existing system have to meet certain requirements. This includes both the selection and qualification.

Design

Pipe - this covers internal and external pressures and loads.

Components - involve all valves, fittings, fabricated assemblies, etc., that are subject to the system pressure.

Welding

Any welding done on a pipeline has to meet the applicable welding requirements. This includes the welding of clamps and sleeves.

Construction

Construction regulations cover a broad range of activities. The regulations are directed to new construction, but also pipe replacement and relocation that is part of rehabilitation work. Also, anything that applies to a new line would certainly be a valid guideline for the rehabilitation of a line.

Some key areas are inspection of materials and work, repair of pipe, installation of pipe in the ditch, backfill and cover over the buried pipeline. In addition, various construction and as-built records are required.

Testing requirements

This is an area that certainly requires careful consideration. The general requirement sections for testing under both the natural-gas and hazardous-liquid regulations have not been definitively interpreted. In the case of Method 2, there would be no question as to the requirements for hydrostatic testing under the requirements of either the gas or liquid regulations. Also, with increased emphasis on protecting the environment, the handling of the test water is very crucial.

Regulations: during and after rehabilitation

Corrosion control

Corrosion control falls into the same category as welding, in that any coating activity would have to meet the applicable regulation. This would include coating material specification, cleaning and preparing the pipe surface, test stations and leads, monitoring and corrosion-control records.

Operations

The operations' requirements cover a broad range of subjects that are essential to the safe operation of any pipeline. These include written operating procedures for normal operations and maintenance, emergency plans and procedures, training requirements, establishment of MAOP (maximum allowable operating pressure), and maps and records. Because rehab work is maintenance, the O&M procedures must also cover this work.

This section of the regulations is the only time that an operator writes his own regulations. The basic regulatory requirement is that he prepare a written plan, and then that he follows it. The operator has the responsibility of developing requirements adequate for the safe operation of his particular system.

We might also note that an operator cannot delegate or contract away this responsibility. He, as the regulated, is always responsible for seeing that these procedures are met, even if a contractor does the work.

Maintenance

One should also be aware that this also covers a variety of subjects, some of which may apply to rehab work. These include line markers, valve maintenance, permanent field repairs of imperfections and damages, maps and records, and the prevention of accidental ignition.

Accident and safety-related condition reporting

This reporting is required by both the gas and liquid regulations. In many cases, the lines are worked under pressure and, in the event of an accident, the accident-reporting requirements would apply. This also applies to the safety-related condition requirements if the time requirement for corrective action cannot be met.

Drug testing

It is required that all operators of pipelines, except master meter systems, shall maintain and follow a written anti-drug plan. This applies to each person who performs on a pipeline an operating, maintenance, or emergency-response function regulated by Parts 192, 193 or 195. This includes contractors who do rehab work.

Indicated in Figs 1-4 are the suggested sections of the Federal Pipeline Safety Regulations that should be considered when planning and executing a rehab job. The possible requirements are shown for Method 1 and Method 2 for both gas and liquid lines.

CONCLUSION

With the continued concern of Congress over the safety of US pipelines in high-density population and environmentally-sensitive areas, plus the increased activities of the Federal and State regulatory agencies, there should be a dramatic increase in rehab work. The pending legislation (HR 1489) requires that certain pipelines be inspected with smart pigs as the minimum level of inspection. In order to meet these demands, the pipeline industry will have no choice, thus making regulatory compliance planning a necessity.

PIPELINE DESIGN FOR PIGGING

INTRODUCTION

The first section of this paper highlights the management aspects of pipeline design for pigging; the second section deals with some of the design details themselves.

The management aspects concentrate on who must supply information at what stage of the project, and how it should be handled.

A pipeline design project is divided into three major design stages:

- conceptual design (basic engineering);
- detailed design and procurement;
- operating manual.

Conceptual design

Information flow is co-ordinated by the project management team. This conceptual design information is used to determine the facilities (or capital investment) and the operational requirements (and operational expenditure) for the lifetime of the pipeline.

Following this, a more detailed estimate can be made to support the feasibility of the project.

Then, the second phase of the project begins, involving detailed design and procurement.

Detailed design and procurement

The conceptual design information is distributed by the project team to the various departments who will specify the pipeline design in detail. This information must be specific enough for use by suppliers, inspectors, expe-

riters and construction contractors. It is recommended that one person is made responsible for the total pigging aspects of the project.

Operating manual

The operating manual is the document providing the operators with information about the operational limits of the installation. As such, it must also detail the engineering considerations of the design.

What happens if we do not follow this sequential information gathering and recording route?

1. We hope that everything will be all right, and allow the project simply to drift.
2. We trust that supplier and construction contractors have a 'crystal ball' to read the minds of the design engineers.
3. We try very hard to prove Murphy's Law that states that what can go wrong, will go wrong.
4. We pass responsibility on, like a hot potato.

DESIGN DETAILS

The main question to be answered when examining the design of a pipeline project is: is there a universal design for all pipelines which will enable them to handle all the pigging activities that may be required?

To answer this question, it is necessary to list all the pigging activities, types of product and types of pipeline.

Pigging activities

Construction -	cleaning testing inspection drying
Operation/ - maintenance	commissioning condensate removal wall cleaning corrosion control

Pipeline design for pigging

Shutdown or - product removal
repair

Types of product

Gas -	with H ₂ O, H ₂ S, chlorine, etc.
Crude oil -	- do -
Injection water -	- do -
White products	

Types of pipeline

Onshore

- well lines: short, small-diameter, multi-line grids, etc.
- transmission lines: long, mainly larger-diameter

Offshore

- | | |
|-----------------------|--|
| - well lines: | subsea to platform
platform to platform
subsea to subsea manifold and
flowline tie-in |
| - transmission lines: | platform to platform
platform to shore |

Comments

(1) The difference between well lines and transmission lines may be simply their life cycle. Transmission lines are designed for at least 30 years' service, while well lines may only be required for 10 years' operation.

(2) Transmission lines usually carry treated product.

(3) Well lines may form a localized grid of short pipelines which may be considered as suitable for portable pig traps and launchers.

(4) Offshore lines may qualify for multi-pig or sphere traps for remote launching and reduced supply-boat visits.

(5) Current designs for inspection pigs are shorter than before, and the difference in length between inspection and cleaning pigs is therefore becoming less important.

(6) Subsea launchers and receivers require a relatively-low capital investment, but need a high operational expenditure. That is why there is a special interest in the development of multi-pig traps and pig diverters (Y-pieces).

(7) Small-diameter gas lines are very difficult to pig, compared to other types of pipeline, and require special attention at the design stage.

Conclusion

All transmission lines should be designed for multi-purpose bi-directional pigging (for cleaning and inspection), with permanent pig traps.

All well lines should be designed for multi-purpose bi-directional pigging (for cleaning and inspection); they may be equipped with portable traps if they form part of a multi-purpose grid.

All offshore lines requiring sphering facilities should be designed to specific requirements in terms of the number of spheres to be launched, and consideration must also be given to provision of sphere tees.

PIPELINE COMPONENTS

In terms of pipeline design costs for future pigging operations, provision of pig-trap stations forms the largest capital investment of any specific component. The pipeline itself, however, has specific fittings and valves which require special attention during the design stage and even during construction.

Tees

Tees can be divided into two types, sphere tees and barred tees. The former are often used in piggable lines because of their constant internal diameter.

Pig diverters

Pig diverters are particularly attractive to designers of subsea-well flowline systems; their application can often reduce the high operational expenditure of reloading a pigging station. A lot of development work has been done in this area by BP in Norway; very limited actual experience is available.

Pipeline design for pigging

Pig-passage indicators

Currently, pig-passage indicators of mechanical design have the longest track record. They are often regarded as unreliable, although any shortfall in performance is usually due to the lack of preventive maintenance.

Pig-passage indicators must be:

- bi-directional;
- flush with the internal pipe wall; and
- retractable and replaceable under pressure.

Furthermore, pig-passage indicators can be equipped with a micro-switch for remote signalling. Such applications usually have an automatic re-set mode, while mechanical passage indicators are manually re-set.

Bends

Bends for pigging should be of the following minimum radii:

4-in	20D
6 and 8-in	10D
10-in and above	5D

Besides the minimum radius, the out-of-roundness should also be limited to 5%.

Special attention should be paid to the internal diameter, as these bends are usually hot-drawn from heavy pipe wall material.

The location of the bends should always allow a straight section of at least three times nominal diameter up- and down-stream. In particular, 30° or 45° offset bends should have a minimum straight length between them of 6ft for pipe diameters to 24in, and 3D for diameters of 24in and above.

Valves

Valves should be specified for pigging purposes with the following requirements:

- full-bore with specified minimum internal diameter;
- guaranteed 100% opening;

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limited or zero by-pass;
vendor's detailed drawings should be submitted with quotations;
valves should be designed to be suitable for vacuum drying or resistant to glycol drying if necessary.

Pipe internal diameter

The pipe internal diameter should be kept constant. The wall thickness of the pipeline determines the internal diameter of all pipeline components (valves, bends, tees, flanges, etc.).

The wall thickness changes for road and river crossings as well as for platform risers should be studied to assess the feasibility of adding extra thickness to the outside wall to accommodate the greater strength requirements at these locations. Maximum deviation of internal diameter from the nominal should be kept to below the figures given in the following table:

Nominal diameter (in)	Maximum deviation (mm)
4	4
6	6
8-12	10
14-20	14
20-36	16
36 and over	20

Any internal diameter changes should be made with a transition piece of 1:5 minimum slope. Special care should be taken with the pipeline design where diameter changes occur towards the ends of gas pipelines.

Pig-trap stations

Pig-trap stations can be subdivided into groups:

- permanent stations for onshore pipelines;
- portable stations for onshore pipelines;
- permanent topside stations for offshore pipelines; and
- permanent subsea stations for offshore pipelines.

Permanent pig-trap stations for onshore pipelines differ mainly in layout from those for topsides' installation offshore due to space limitations. Simi-

Pipeline design for pigging

larly, subsea installations differ from the rest because of the necessity for remote-control operation, as well as because of the generally-harsher environmental aspects of subsea operations.

For toxic (H_2S -laden) products, pig-trap station piping should be extended with flushing connections to allow the toxic product to be expelled from the trap prior to opening. Otherwise, the layout of the piping will be similar for both liquid and gas service.

Besides sampling points and filters, pig traps are the only piping components that are opened during normal operations and, as such, require that extreme care shall be taken with their design to protect operational staff.

Pig-trap stations should be laid out so that the functions of valves and bypasses are clearly indicated. Standardization of layout is therefore recommended, as is colour-coding of flushing piping and valves to highlight their functions.

Portable pig traps

Portable pig traps should only be applied in the sizes of 12-in nominal diameter and below. They should only be considered if the capital investment involved outweighs the operational expenditure. This will only be the case if a large number of the same sized pig traps are used in a pipeline grid, requiring a low-frequency pigging operation (e.g. inspection pigging). There is not much experience available in the use of portable traps to date.

Offshore traps

Pig traps on platforms may differ in layout from onshore installations due to space limitations. The connections may be in the vertical plane to save space.

Vertical receiving traps are not recommended; vertical launching traps have proved to be of limited success, and should be limited to the absolute minimum in the smaller sizes only. Multiple sphere-launching traps should also be designed to handle inspection pigs; a cartridge design can be considered for such an installation.

Editor's note:

Readers are referred to the paper given by Cees Bal at the series of seminars "Pipeline pigging an art or a science?" organized by Pipeline Equipment Benelux for further detailed information about pig-trap design. The author's address is PO Box 186, 2700 AD Zoetermeer, Netherlands.

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PRE-INSPECTION-SURVEY ACTIVITIES FOR MAGNETIC-FLUX INTELLIGENT PIGS

INTRODUCTION

The determination of the accessibility of a pipeline prior to intelligent inspection, and deciding on the level of preparation that will be required, are sometimes subject to differences of opinion between pipeline operators and inspection contractors. This may ultimately result in a failure to achieve the specified inspection results.

The pipeline operator expects the inspection survey pig to report pipe-wall anomalies (internal and external) as small as 12mm diameter and only 3mm deep. These are to be found and sized in, for example, a 30-in diameter, 100-km long pipeline, which has a pipe-wall surface of 478,536sq m. It is obvious that the pipe wall should be accessible and the running conditions should be optimized in order to achieve the desired inspection result.

Just for comparison, a 30-in intelligent pig travelling at 3m/s produces approximately 150,000 measurements per second, and passes over a 12-mm anomaly in 0.004sec. In this available time, the sensors must record measurements to determine and confirm the metal loss and decide on internal or external location.

This paper describes the possible causes for misunderstanding by detailing all the activities required prior to a pre-inspection survey. The fact that a single cleaning pig run does not produce conclusive information on the pipe-wall surface condition may give rise to misunderstanding. Hence, this subject and many others are detailed below.

Pipeline surveys are carried out as part of an overall maintenance programme; the inspection contractor should therefore have access to all relevant pipeline data in order to be able to present the survey report in the format that fits the maintenance programme.

PRE-CONTRACT ACTIVITIES

The activities prior to an inspection can be summarized as follows:

- gather all relevant information;
- determine if inspection can start, or if further cleaning is required;
- design a pre-survey cleaning programme;
- establish if debris is present;
- remove debris by pigging until the inspection pig can be run.

These, and related, activities are discussed below:

Relevant information

Relevant information shall be gathered and should be recorded in a pipeline-inspection reference file. The information should include:

- design parameters;
- mechanical properties;
- operating data (normal and during survey);
- anticipated pipe wall condition;
- design (as-built) drawings;
- welding records;
- any remarks about the history of the pipeline construction or operations that may be relevant to the corrosion rate (e.g. hydrostatic test water remained in the pipeline for two years before start-up, the line was flooded with untreated water, flow conditions were very different in the past, deviation in cathodic protection readings, etc.)

The corrosion survey equipment will produce a snapshot of the pipe-wall metal loss. This is useful information, of course, and is suitable for identifying defects for immediate repair. However for future planning of a cost-effective maintenance programme, the information from the corrosion-reference file and the results of the survey should be merged for further study.

Inquiry preparation

Although this paper deals mainly with technical matters, the major commercial aspects are highlighted:

Pre-inspection-survey activities

the inspection survey is carried out as a service-type operation, for which the contractor makes available the equipment and personnel to execute the task;

the equipment produces electronic data;

the contractor's costs include:

- preparation of the inspection pigs;
- transporting equipment and personnel, including lodging;
- making available the equipment and personnel for the duration of the contract;
- processing the electronic data into a final inspection report;
- research and development;
- overhead and profit.

Job planning

Planning an inspection-survey contract usually includes:

- pre-survey meeting;
- mobilization of equipment and manpower;
- pigging in three stages:
 - 1) run bi-di type pig with gauge plate;
 - 2) run electronic geometry pig;
 - 3) run corrosion-detection pig.

The planning of the job may be such as to require all the equipment to be mobilized for each pipeline, in which case stand-by costs will have to be charged in case stages 1 or 2 prove that stages 2 or/and 3 can not be undertaken without further preparation.

In case of doubt on the results of stages 1 or 2, the job may be costed to allow separate mobilization after completion of each stage.

- initial report;
- verify initial report (dig up);
- final report.

The contractor may be depending on the client for import/export facilities and local transport in certain countries. Stand-by rates apply in case of exceeding the basic time.

Insurance

This may differ from country to country, but basically:

- client and contractor are responsible for insuring their own equipment during the survey;
- client and contractor indemnify each other for damage brought upon the other;
- client and contractor refrain from claiming consequential losses.

In addition to these standard service-contract insurance requirements, the client will remain responsible for damage to the inspection pigs as the result of incorrect operation of the pipeline system.

Responsibilities

The contractor is responsible for preparation of the equipment to the specifications required for the job (unique for each pipeline), and for providing the equipment in a "fit-for-purpose" condition to the job site (a final pre-survey test is carried out on site).

The client is responsible for handling the equipment on site and running it in the pipeline in accordance with pre-agreed conditions (flow, pressure, temperature and pipe wall surface condition). Repairs to the contractor's equipment, other than normal wear and tear, will be charged to the client.

Re-runs as a result of the contractor's fault will be provided free of charge, for which the client will make available the pipeline and provide all contractually-agreed conditions.

Re-runs as a result of the client's fault will be charged at the pre-agreed rates.

Technical information

The tender request document shall include basic information about the pipeline design, condition and the operational conditions to which the inspection pigs will be subjected.

The reporting level and reporting format shall be defined.

A proposed plan should be included. Drawings and welding records do not necessarily have to be included during the tendering stage, but their availability (or unavailability) should be mentioned.

Restraints, if any, should be mentioned (e.g. intermittent operations, other operational limitations, weather window, etc.)

PIPE-WALL SURFACE CONDITION

The surface condition of the pipe wall can usually be predicted from the available pipeline data. The following guidelines indicate whether an inspection survey can be started or a pre-survey cleaning programme is required.

The inspection survey can be started if the pipeline is either:

(1) new (a 'baseline' survey), and:

- the construction procedure has prevented debris entering the line;
- the test water was removed using bi-di pigs, the pigs showing no sign of excessive wear and not bringing in debris;
- the product is clean (e.g. treated gas, white products, injection water, etc.)

or (2) the pipeline is:

- proved clean by regular pigging (a minimum of 4 times/year) with bi-di pigs, and has perhaps even been surveyed before;
- carrying a clean product (e.g. treated gas, white products, NGL, LPG, injection water, etc.)

It is suggested that a pipeline pre-survey cleaning programme will be required if the pipeline:

- is more than 10 years old and is not pigged regularly;
- carries products that form and/or settle-out hydrates, iron sulphates, salts, sand, waxes or asphalts;
- is more than 60km long.

These lines could be gas, crude-oil or water-transmission lines.

Comments

(a) It is more difficult to assess whether deposits are present in longer lines (over 60km).

(b) The lines may be dirty either as a result of construction debris or debris which has slowly accumulated over many years.

(c) Lines that are rapidly accumulating a layer of deposit require special arrangements, i.e. a corrosion-inspection pig should be run immediately after the cleaning programme.

(d) The normal cleaning runs maintain the flow requirements adequately. The corrosion pig, however, introduces a magnetic field into the pipe wall via very strong permanent magnets and brushes. These may scrape off more deposits, which may interfere with the sensors' reading of magnetic signals. It is clear that special arrangements have to be made to prevent failure of the survey; it is suggested that a number of cleaning pigs are run at frequent intervals, with the results from each run being carefully recorded and studied.

(e) The formation of so-called 'black dust' (iron sulphate) in gas pipelines is caused by a reaction between the material of the pipe wall and the gas content. The dust is usually very abrasive, wearing down discs/cups at a tremendous rate. Again, it is very difficult to remove it from longer lines (100km and over) due to the wear. Also, the dust may ignite when exposed to the air, and so stringent safety precautions are recommended.

Since the debris is usually concentrated in the most interesting portions of the pipeline (the bottom of the pipe cross-section, low spots, etc.), lack of recorded data may reduce the efficiency of the survey by up to 80%.

Debris accumulation can result in:

- mechanical failure of the inspection pig, jamming the odometer wheel system (loss of location reporting);
- lift-off of the magnetic brushes, and consequent loss of magnetic field (reducing the level of detection);
- lift-off of the sensors, and consequent failure to detect magnetic-flux leakage (reducing the level of detection);
- accumulation of ferrous debris disturbing the sensor readings (confusing the detected data);
- total or partial destruction of the corrosion-inspection pig itself.

PIPE-CLEANING PIGGING

The pipe-wall surface condition can only finally be assessed by the use of pigging, although pigs only produce consequential evidence. However, as stated in the introduction, a single pig run does not produce conclusive information.

The reason for this is that the results of pigging are assessed by the amount and quality of debris that is accumulated in the receiving pig trap, and by the physical condition of the pig after the run. These results provide a certain amount of information, but leave three unknowns:

- pig performance on this run;
- debris quantity;
- debris quality.

These unknowns are further qualified by the following factors:

- pigs wear down in the pipeline and, as such, their performance capability reduces during the run (cup/disc wear is very much affected by the vast amounts of dust in gas pipelines);
- greasy pipe walls lubricate the cups/discs, reducing the pig performance;
- temperature differences influence the stiffness of the cups/discs;
- the amount of debris may exceed the pig capacity (in long lines);
- the adhesion of debris to the pipe wall may be greater than the pig can scrape off.

It is for these reasons, among others, that more than one pig run is required to assess the pipe-wall condition.

Pig performance

Pig performance can only be assessed by comparing one type with another. However, they will never have identical running conditions; the added complication of the dual function of the pig (scraping off and pushing out debris over long distances), makes a true comparison impossible, and assessment very difficult.

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Hence, the only assessment that can be made is gathering field-performance feed-back and examining the design of the pigs. In regard to pig design, the following points can be made:

- bi-directional (bi-di) pigs with guiding and oversized sealing discs are much more effective than conical-cup type pigs;
- brushes with coil-type power springs are more effective than those with leaf-type springs;
- pig trains of three pigs are more effective than running three pigs separately. (What is scraped off by one pig is pushed out by the next in the train before the debris settles down again);
- pigs with by-pass and spider noses push more debris out than those without by-pass (provided sufficient flow is present; for a liquid 1m/sec minimum, and for a gas 3m/sec minimum);
- increasing the number of guiding discs per pig has a more than proportional effect on increasing the push-out performance;
- mounting brushes on pigs in dry gas pipelines improves the stability and reduces the disc wear; (the black dust in gas pipelines causes the discs to wear down. This prevents the pig from rotating, causing excessive and uneven wear);
- the weight of the pig has little or no effect on the cleaning performance.

This means that for adequate pre-survey cleaning:

- (a) in a pipeline that is relatively clean, a limited number of standard-type pigs can satisfactorily prepare the line;
- (b) in a pipeline where a good regular pigging programme is undertaken, a simple increase in frequency can suffice (or maybe the use of a different type of standard pig);
- (c) in a pipeline with a recognized problem (wax, dust, over 100km in length, etc.), a specially-designed pre-survey cleaning programme will be required with specially-adapted pigs and the use of pig-train techniques.

Conditions in low-pressure/low-flow gas lines are not considered in the review of cleaning problems outlined here. However, these operating conditions result in uneven speed. Trial pigging should be carried out using differential-pressure measurements and conscientious recording (low pressure for pipelines below 14-in diameter is taken as 60bar; in pipelines from 16-24in diameter, 30bar; and in pipelines above 24in diameter, 20 bar; low flow is 1m/sec or less).

Pre-inspection-survey activities

With regard to the design of cleaning pigs, the following features are of importance:

Brushes/blades	materials configuration suspension
Cups	shape mounting (influences stiffness) thickness hardness (over) size number of cups per pig
Discs	hardness thickness (over) size mounting (influences stiffness) number of discs per pig

This information, together with the available pipeline data, forms the basis for determining the pre-inspection cleaning programme.

OPTIMIZATION OF INSPECTION RESULTS

Cost-effective suggestions for optimizing inspection results include:

(a) analyze available information in-house, using the above-mentioned suggestions, at no external cost;

(b) provide a written analysis to the pipeline inspection contractors tendering for the inspection contracts. It is essential to provide information for each pipeline;

(c) decide whether it is feasible to carry out the cleaning activities using in-house personnel and equipment, or by asking the contractor to include it in the scope of work. It is also suggested that consultancy services should be considered for the supervision of the in-house cleaning activities in a cost-effective manner;

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(d) note that special attention should be paid to pipelines with a high deposit drop-out rate, putting a time restraint on the cleaning/inspection sequence (injection of chemicals may be considered);

(e) weather - or production - windows may form a constraint due to:

- shipping the tools offshore;
- high product temperature in summer exceeding inspection equipment specifications;
- low product temperature in winter increasing deposit formation (cloud or pour point);
- high demand of product exceeding maximum speed levels of inspection tools (over 4m/sec);
- low demand of product giving insufficient flow to run the inspection tool (under 0.5m/sec). On long pipelines, even the battery capacity may be exceeded due to long running time (exceeding 4 days);

(f) provide complete pipeline data including:

- historical data (with relevant notes on construction activities, e.g. left the line full of water for two years, and operational changes, e.g. initial low-flow conditions, increase of water cut three years ago, etc.)
- relevant maintenance experience (e.g. cathodic protection system failures, known corrosion, etc.)
- anticipated condition of the pipe wall
- pigging experience and results
- suggested pigging plan (specifying the level of detection and the reporting format required)

Two simple rules are that time spent in the office is a lot cheaper than time spent in the field, and overspending always attracts top management's attention.

Although this discussion may appear very detailed, assessment of pigging runs is a specialized job to be done by trained engineers. Instant decisions are often required in order to determine the pig configuration for the next run.

CONCLUSION

This paper has the aim of sharing the author's pigging experience, achieved from many pipeline pigging operations, with professional engineers required to deal with a variety of different pipelines. It is hoped that the ideas

discussed may encourage pig users to handle what may have become familiar problems in a different and more efficient manner.

The levels of inspection confidence and accuracy demanded by today's pipeline operators require the advanced inspection equipment to check every square centimetre of the pipe wall. Multi-million dollar maintenance programmes are based on the information thus gathered.

It is clear, therefore, that only the best results are acceptable, and pre-survey cleaning is an important link in the chain leading to achievement of this aim.

Finally, it is worth noting, for the benefit of all concerned, that the unexplored condition of the pipe wall does not lend itself to lump-sum-type contracts for cleaning.

The author welcomes comments on the topics discussed here, in the hope that shared experience may one day lead pigging from being considered an art to being accepted as a science.

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PIGGING AND INSPECTION OF FLEXIBLE PIPES

INTRODUCTION

The current proliferation in the use of flexible pipes from the drill floor to the seabed largely derives from early successes achieved in the late 1970s in the application of flowlines and static risers. At that time, there was an industry demand to develop an alternative pipeline construction to that of rigid pipe, which could be quickly laid using more economical installation vessels and which could offer greater tolerance for misalignments. Early product developments utilized a composite of steel and polymer materials to construct a layered structure which could offer greater chemical resistance and structural flexibility than that offered by steel pipe. Technical development progressed along two paths - that based on making submarine power cables; and that based on the making of steel-reinforced hoses.

Today these two manufacturing technologies offer the oil industry alternative product constructions known as the *bonded* and *non-bonded* type flexible pipes. By utilizing the inherent chemical resistances and mechanical properties of its component parts, flexible pipe offers a composite construction having the advantages of: a low bending radius; good thermal characteristics; high dampening coefficient; and high impact resistance. These and other favourable properties related to stress distribution have prepared both types of flexible pipe for use in increasingly more-demanding applications. In fact, since 1979, more than 1600km (1000miles) of flexible pipe has been installed using both constructions.

As a result of successful operational experience with quasi-static risers and dynamic topside jumpers in the past 15 years, pipe developments extended this technology into the field of dynamic catenary risers. The need for such risers began in Brazil in the early 1980s due to Petrobras' commitment to bring oilfields onstream quickly using subsea and floating production systems. As an alternative to using rigid risers having articulated or swivel joints, flexible risers have been installed to connect fixed seabed hardware to floating units.

As a result of the high consequential inertial loads imposed largely by differential motions between the vessel and the seabed and, as a result, environment forces, flexible risers have been used to effectively provide a motion-compensation system.

The increased availability of various flexible pipe designs has increased the industry's need for greater awareness concerning pipe properties, ageing effects, fatigue lifetime, and inspectability. What is clear is that flexible pipe is not a product of a "black-box technology", and can be technically assessed and verified with regard to its overall integrity. However, in order to formulate both a methodology and a programme for the inspection of flexibles, it is essential to have a clear appreciation of their construction aspects and correspondingly complex behaviour. In this way the presence and significance of defects can be related to any impact on structural reliability.

UNDERSTANDING PIPE CONSTRUCTION

Flexible steel reinforced pipe is a generic term defined by the American Petroleum Institute [API, RP 17b 1987] as being "... a composite of layered materials which form a pressure containing conduit. The pipe structure allows large deflections without a significant increase in bending stresses". Pipes are reinforced axially and radially by the incorporation of steel chords, flat tendons, helixes and/or cylindrical carcasses; construction will either be of the bonded or non-bonded types.

Bonded pipe construction

Bonded pipes are those where the component materials are applied as alternating layers (polymer, steel, fabric) using chemical bonding agents to achieve initial adhesion strength. Elastomeric materials and textile-reinforced fabric plies are laid over and between several layers of cross-wound, pre-tensioned steel reinforcing elements preventing steel-to-steel contact. To achieve a homogeneity as a single structure, the pipe is vulcanized in a carefully-controlled heating oven (applying temperature in a stepwise manner together with pressure to the structure) permitting cross-linking of the polymer structure and curing of the matrices involved.

In a bonded pipe, flexibility is provided by axial and shear deformations, and there are virtually no relative movements between interfacing surfaces. This is especially important when considering wear rates and, ultimately,

fatigue lifetime. Due to this lack of slip between layers there is little heat build-up or internal friction in this construction.

Non-bonded pipe construction

Non-bonded pipes are also made up from alternating layers of polymers, steel reinforcement, and textile tapes. The individual polymer layers are extruded over steel structural elements, but no adhesives are used. Separations of layers allows for individual layer slip. Lubricating media or intermediate sheaths are installed to reduce internal friction. The inner polymer sheath is designed to serve as a leak-proof fluid conduit, whereas the outer sheath serves to keep the reinforcement steel together while protecting the inner structure from abrasion forces. This superposition of polymers and steel can induce residual volume variations (due to pressure effects). As layers are separated, settling will occur. As a result of component variations and relative motions due to pressurization, there will be flexible elastic deformations.

Polymers and gas permeation

The polymer (plastics and elastomer) components in flexible pipe largely serve as fluid conduits or chemically-resistant structures. As such, ageing and resistance to hydrocarbons and gases are important. Plastics or polymers are composed of long-chain molecules which form a network structure. Although intermolecular distances are extremely small, molecular chains perform continual thermal vibrations, and it is these vibrations which permit the passage of gas molecules through the structure [Makino *et al.*, 1988].

When gases or fluids containing gas are passed through a polymer pipe, gas molecules permeate through the polymer layers as a result of absorption, solution, and diffusion mechanisms. Consequently, gases can accumulate in interstitial spaces of the metallic armour and between the inner and outer polymer layers. This accumulated gas gradually increases over time and as a result of increases in pressure. Gas migration through the structure is an operational concern, but becomes very important when considering entrapped gas behaviour during rapid pipeline depressurization(s). During such an occurrence, entrapped gas volumetrically expands, exerting significant forces on inner polymer sheaths. Should such forces overcome the shear strength of the polymers, permanent deformations or even collapse could result; this is known as ED (explosive decompression). For most gas pipe designs, a stainless steel inner carcass or corrugated tube is used to prevent such deformations from occurring as the steel liner is not affected by such

pressures. To handle entrained hydrocarbon gases in well fluids on a more routine operational basis, different flexible pipe designs utilize alternative methods:

Methods for handling diffused gases:

a) especially-thin portions of external polymer sheaths can be incorporated in the structure [Makino *et al.*, 1988] so that as interstitial pressures in the armour layer rises, the thin portions periodically rupture, thus reducing internal area pressure;

b) interstitial spaces are connected so as to lead accumulated gases along the pipe axis and then through "bursting discs" located at the pipe ends, so that gases are continually released;

c) special polymers layer(s) are used in a bonded structure which will swell when exposed to gas and saturate without permanently deforming. These layers allow expanding gases to outwardly diffuse through the more permeable outer cover layers;

d) a non-permeable, gas-tight pipe is made using a continuous, corrugated inner steel tube as the main fluid conduit. The advantages of using this non-permeable structure are that (a) under normal operations, gas migration into the polymers is prevented; and (b) even if the lines should leak, pressure will be contained by the normal reinforcement layers; and (c) the liner's shape itself has sufficient residual strength to resist explosive decompression effects.

COMPOSITE CONSTRUCTION AND COMPLEX BEHAVIOUR

Flexible pipe construction, whether of the bonded or non-bonded type, is made from a composite of layered or even sandwiched materials. Materials of *Kevlar* or *Aramid* reinforced elastomer fabrics, for example, are used to prevent elastomer extrusion during the application of cross-windings (bonded pipes). Similar sandwiched layers are used to increase strength or burst pressure capacities, particularly for pipes subjected to dynamic bending. As another example, ceramic-impregnated elastomers are applied to the pipe

Pigging for flexible pipes

Steel pipe

homogeneous material
construction
non-layered construction
near-round shape
monolithic material
low dynamic fatigue
resistance
simple structural behaviour
low flexibility (up to 500 x i.d.)
smooth bore

Flexible pipe

inhomogeneous construction
layered construction
slightly oval shape
composite of materials
high dynamic fatigue resistance
complex structural behaviour
high flexibility (8-10 x i.d.)
smooth or rough bore

Table 1. Comparison of properties and characteristics for rigid and flexible pipes.

outside diameter to form a durable yet resistant covering capable of taking abrasion forces while also resisting hydrocarbon fire (typically to Lloyds Bulletin at 700°C for 30mins without loss of content).

The composite construction also serves to reinforce the individual pipe components and enhance their individual strengths. By embedding steel chords used for axial reinforcement in elastomer matrices, Pag-O-Flex of West Germany has found [Joint Industry Report, 1987] that the breaking load in long-term axial pull tests for embedded steel chord is considerably greater than that for bare steel chord. This is particularly important when considering riser applications, where a catenary configuration is used and combined loadings occur in the steel reinforcement due to internal pressure, tension, and bending effects.

Other composites, such as epoxies, graphites, and glass fibres, also offer significant technical benefits by combining high fibre strength with good material resistance to corrosion or chemical degradation. However, composites [Lefloc'h, 1986] are often difficult to assess with regard to structural strength and changes in mechanical properties due to the influences of ageing and material degradation over time. Certain properties in material construction can lead to a degree of variability in product qualities and a lack of precise knowledge as to which property principally governs at any one point in an operational lifetime. Furthermore, distribution of stresses within individual layers is not always linear or simple to assess. It can be said that such composites exhibit a complex rather than simple structural behaviour, i.e. the material behaves anisotropically (forces do not act in a single direction); the construction is inhomogeneous; and the failure modes can be compound.

In order better to understand how to inspect or make a condition assessment for flexible pipe, one must first make a comparison between the general properties and characteristics of flexible pipe with that of steel pipe. Some of these differences are illustrated in Table 1 [Neffgen,1988].

As can be seen from Table 1, considerable differences exist between rigid and flexible pipe. Flexible pipe's complex behaviour in practice means:

- bending moments and strains cannot be easily calculated;
- some component materials exhibit non-linear behaviour;
- differences exist between component elastic moduli which must be analytically explained;
- strain distribution around the pipe is axi-symmetrical.

DEFECTS AND MODES OF FAILURE

To understand the structure of flexible a pipe is to appreciate the complexities of its behaviour and then to relate those to the presence and significance of defects. The purpose of any inspection programme is principally directed at [Bea *et al.*,OTC,1988]:

- detection and documentation of defects which can lead to a significant reduction in serviceability characteristics;
- defining what should be inspected, when, and how;
- establishing a long-term database and feedback loop;
- establishing the significance of a defect and/or the need for remedial action.

Such an inspection programme initially must focus on the identification and determination of "...significant defects which can affect structural capability, i.e. the ability of the structure to remain serviceable (not to fail) during its projected operational life" [Bea *et al.*,1988]. The importance of establishing a database for pipe defects and understanding how such defects can propagate are important in relating significance with regard to failure modes.

Two modes of failure have been identified as having principal impacts on structural integrity, those being wear and fatigue. Veritec [Veritec joint industry report,1987] has defined wear as "...the damage to a solid surface caused by the removal or displacement of material by the mechanical action of a contacting liquid, solid, or gas. Wear is mostly mechanical, but may combine with chemical corrosion".

Pigging for flexible pipes

Wear or fretting of steel components, *not* fatigue, has been found by Pag-O-Flex after 2½ years of dynamic testing of 6-in x 6000psi riser pipes to be the most probable mode of failure. Wear is of particular concern for dynamic flexible riser systems because pipes are bent towards their minimum radius of curvatures, and may also be subjected to high crushing loads both during installation and operation (especially at touch-down points and over steel arches). O'Brien and others [OTC 4739,1984] have stated that "a deepwater catenary system is prone to wear because of the overall system elasticity and surge motions". These wear concerns increase with system motions, water depth, imposed loads, and the overall excursions of the riser configuration.

Fatigue, i.e. the development of weaknesses in the polymeric or steel components due to repeated cycles of stresses, has proven difficult to quantify. To relate stress levels in individual pipe layers to cycles to failure it has been necessary to perform long-term (more than 1 year) component and pipe dynamic tests at simulated operational and environmental conditions. As stated above, Pag-O-Flex's joint industry programme subjected pipes to dynamic bending and tension exposed to 100-year storm conditions for more than 20million cycles without pipe failure, i.e. no loss of pressure or fluid [Pag-O-Flex, JITP Report,1987]. Through the development of S-N curves for both component and pipe structure, as well as improvements in ultimate capacity models, a better understanding of fatigue lifetime can be gained. The other modes of failure for flexible pipe can be summarized as being [Veritec,JIP/GF2,1987]:

- disbondment of bonded components;
- fretting or internal wear;
- corrosion of steel components;
- fatigue failure of component part(s) or the structure itself.

Inspection of flexible pipes is complicated not only because of the composite, layered construction but also because of a pipe's complex behaviour. Because of the high design safety factors and surplus strength elements used in its construction, the pipe can compensate for the presence of defects. Favourable aspects concerning such a matrix-type construction to be noted are: that a high degree of structural redundancy exists; and gradual leakage rather than sudden rupture is the most probable effect of a failure. This factor should be reassuring to operators, particularly when transporting live crude or gas in flexible pipe.

Efforts in the inspection of flexible pipe can therefore be focussed primarily around two categories of defects [Neffgen,Subtech,1989] which can have an impact on the structure because of leakage:

defects which can lead to a leakage including:

- holes through the pipe structure;
- excessive gas diffusion;
- separation(s) between pipe body and body/end fitting.

defects which cause a change in pipe cross-section including:

- ovalization of the structure;
- collapse of the inner carcass or liner;
- erosion or build-up of deposits;
- creep of the inner carcass or radial reinforcement.

FORMULATING AN INSPECTION PROGRAMME

In order to establish a reliable and cost-effective inspection programme, pipeline operators should not only review relevant codes of practice, company and statutory requirements, but should also work with pipe manufacturers to formulate specific inspection requirements. Such a programme has been proposed and is now directed by SINTEF of Norway. A programme would need as input criteria much of the information obtained by the individual manufacturers [Neffgen,Subtech,1989].

In addition, for such a programme to be established, it is necessary to [Jamieson,1986]:

- establish a methodology for inspection while prioritizing inspection points;
- develop a means to classify defects and interpret retrieved inspection data;
- ensure a ready access will be available to relevant areas to be inspected;
- develop and have available suitable inspection tools which can distinguish signals received from flexible pipe's different layers.

Due to the layering effect in composite structures, this latter requirement may be more difficult to achieve than for steel pipe inspection. For one point when using ultrasound to examine pipe integrity, it should be remembered that composite materials exhibit anisotropic behaviour. Rose [ASNT,1984], in the inspection of epoxies, has found that discriminating between pipe layers is as difficult as discriminating between structurally-sound and -unsound materials. Special considerations must therefore be paid to the fact that wave velocities change through individual layers and the reflected signals tend to be very noisy due to ply and material response echoes.

Corrosion monitoring can also be a problem, because most NDT tools have been primarily developed to aid in the determination of global corrosion processes rather than local ones. Because of the rough bore of flexible pipe and due to the irregular geometry of the inner steel carcass or liner, turbulent flow conditions can exist which can aggravate the predominant corrosion mechanism, local crevice attack. Due to the generally-high chloride contents in well fluids and in consideration of increasing reservoir temperatures (up to 130°C), particular attention needs to be paid to steel selection and monitoring carcass surface condition.

PIGGING CONSIDERATIONS

Pigging experience with flexible pipes has been largely confined to applications outside Brazil and generally where hydrate or wax build-up in the pipeline can be expected. This requirement will probably be introduced as Petrobras moves into deep-water developments where low fluid temperatures can be expected. Pigs can help maintain the reliability of a pipeline system generally by: reducing pressure drop, improving flow capacity, and controlling the build-up of sand, liquid, wax, and hydrates. Some pigging operations, such as scraping and inhibition, can also play a central role in boosting the corrosion protection of the pipeline system. Pigging frequencies and selection of pigs will depend on the operator's philosophy, the degree and rate of deposition on the pipe wall, and governing critical constraints.

Probably the greatest use of pigs in flexible pipe occurs during factory release testing (for pipes on storage reels) or during system hydrotesting. Pigs are used (principally for non-bonded pipes) for filling and dewatering purposes as well as to determine pipe obstructions. In non-bonded pipe, the inner liner (polymer) or carcass (steel) is not formed around a fixed mandrel as with some bonded pipes, and therefore some i.d. variations can exist. Also, when pressurizing/depressurizing a pipe, air can pass through the gaps in the carcass structure, making it not always possible to remove entrapped air. Pigging is therefore used to improve air-removal operations and following pressure test completion, to dewater long-length flowlines.

When considering pig selection, it is important to note certain factors concerning the construction of flexible pipes. Firstly, there will be variations in i.d. along the bore of the steel pipe/flexible pipe route. The manufactured diameter of flexible pipe generally comes in even numbers (e.g. 2in, 4in, 6in) and tolerances on i.d. are much tighter than for steel pipe, typically 2-3% or less. This fact means that at end connector areas, restrictions to pigging could

exist. Also, as the nominal bore of the corresponding steel pipe will be less (by 5-10%) than that of the flexible bore, there is every chance that standard pig sealing arrangements will be inadequate. To prevent fluid by-pass, a double-cup arrangement is therefore recommended.

The steel materials used for the inner carcass are generally made from stainless to 316L, austenitic steel (6% Mo, 21% Cr), or duplex. When wire brushes or steel gauging plates are used, their material compatibility must be ensured to prevent damage or contamination to the stainless steel (or sometimes to the brushes themselves).

When selecting cups, blades or gauging plates for use on pigs, it is also important to note that carcass wall thicknesses are generally only of the order of several millimetres. Their profile is a convex wave shape and spaces will exist between adjacent waves. This means that inappropriate pig selection could cause extended blades to jam or even become obstructed in the pipe.

Flexible pipes are by definition and application flexible in catenary, i.e. they are not rigid in bend areas and are likely to have changing radii of curvature. Particularly for dynamic catenary riser applications, pigging should not be considered for radii generally less than 5D, bearing in mind pipe minimum bend radii are generally 8-10 times i.d. Should small radii be required, a steel arch or bend restrictor may be required to safely control curvature.

When using sensing pigs to determine ovality or assess pipe internal condition, further care must be taken, as flexible pipe is a naturally slightly oval structure and will be even more so after elongation and at areas of greatest bending. When considering using intelligent pigs, it should be noted that these devices have been specifically developed for large-bore steel pipe. They largely operate on the principles of magnetic flux (whereby disturbances in an induced magnetic field are related to metal loss); or they use ultrasound inspection (whereby contact probes issue short ultrasonic pulses through the pipe wall and sound transit time is converted to wall thickness measurement). Difficulties exist with these devices due to: flexible pipe's relatively-small bore; the thinness of the steel carcass (0.5-4.0mm); and because of the problems of ultrasonic wave scatter in individual pipe layers.

In summary, pig selection should be carefully made with regard to the special aspects of flexible pipe construction and in view of the need for the pig to pass through without becoming obstructed or causing damage.

Pigging for flexible pipes

Defects

	<i>Geometry changes</i>	<i>Material degra- dation</i>	<i>Cracks & breakage in steel comp.</i>	<i>Cracks in polymer layers</i>	<i>Dis- bonding</i>
Method					
Thermography	X	X	X		X
X-ray and gamma radiography	X	X	X		X
Acoustic methods		X	X		X
Tracing isotopes			X	X	X
Cable-based leak detection			X	X	X
Magnetic induction			X	X	
Eddy current		X	X		
Photogrammetry	X				
Borosopes	X	X	X	X	
Ultrasonic inspection		X	X		X
Holography	X			X	X
Impedence		X	X		

Table 2. Relationship between pipe defects and recognition by various equipment.

RECOMMENDATIONS AND CONCLUSIONS

Flexible pipe is an inhomogeneous structure which because of its composite construction exhibits a complex behaviour. Due to the roughness of its internal bore and differences in the mechanical properties of its varying components, it is essential to gain an appreciation of this new pipeline technology before an inspection programme can be formulated. Inspection of flexible pipe is possible and has been previously reported [Neffgen, 1988]. A number of specifically-adapted techniques have already been tested and their applicability is illustrated in Table 2, which also illustrates the relationship between effects caused by the most likely defects and the ability of a NDT

tool to recognize them. The table has been formulated as a result of two studies performed by Pag-O-Flex for Norwegian oil companies, and as a result of canvassing more than 60 NDT equipment operators.

The effects identified in the table are a result of changes in the pipe structure caused by the presence of defects. The techniques listed are those which have been short-listed as being reliable because of (a) prior industry experience; (b) manufacturer experience; or, (c) because they have been used to inspect similar composite structures with a degree of success.

What has been clear from previous studies is that improvements in noise filters, enhancement of backscatter techniques, and better live imaging techniques, are required to make market-available equipment fully ready to undertake flexible pipe inspection. A closer co-operation is also required between pipe manufacturer and equipment supplier in order to develop a system for defect recognition and classification if this technology is to establish itself alongside that of rigid pipe inspection.

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ENVIRONMENTAL CONSIDERATIONS AND RISK ASSESSMENT RELATED TO PIPELINE OPERATIONS

IN COMMON with many industries, environmental protection and preservation has not been a key factor in the historic development of the pipeline industry. This situation can be attributed to two factors:

The development of the nation's hydrocarbon reserves historically has been a national priority for the United States - and as a result, the pipeline industry has been allowed to progress unfettered by some of the rules and regulations imposed on other developing industries. For the most part, the pipeline industry has had a very good safety record as well as a reputation as a clean and efficient industry.

However, during the last 20 years, there has been a significant change in the pipeline industry's view of the environment and in the environmental regulators' awareness of the pipeline industry. The past two decades have witnessed the proliferation of numerous environmental regulations, some of which have had major impacts on the financial well-being and day-to-day operations of many pipeline operators.

The major environmental regulations that may affect pipeline operations fall into five broad areas: (1) occupational protection statutes; (2) laws on transporting chemicals and hazardous substances; (3) chemical use and assessment laws; (4) environmental protection statutes; and (5) laws regulating clean-up of unintentional disposal of chemicals. Table 1 details these broad areas of environmental regulations and the specific laws within these areas.

Pipeline Pigging Technology

<u>Area of Concern</u>	<u>Environmental regulation</u>
Environmental Protection	- o National Environmental Policy Act (NEPA) - o Clean Water Act (CWA) - o Clean Air Act (CAA) - o Safe Drinking Water Act (SDWA) - o Resource Conservation and Recovery Act (RCRA) - o Regulation of radioactive materials by the United States Nuclear Regulatory Commission (NRC) - o Federal Water Pollution Control Act (FWPCA) - o Federal Environmental Pesticide Control Act (FEPCA)
Occupational Protection	- o Occupational Safety and Health Act (OSHA) - o Regulation of radioactive materials by NRC - o Superfund Amendments and Reauthorization Act (SARA) - o Asbestos Hazard Emergency Response Act (AHERA)
Chemical Manufacture and Use	- o Federal Food, Drug, and Cosmetic Act - o Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) - o Toxic Substances Control Act (TSCA) - o SARA - o Regulation of radioactive materials by NRC
Transportation	- o Hazardous Materials Transportation Act (HMTA) - o RCRA - o TSCA - o Transportation Emergency Reporting Procedures (TERP)
Cleanup Actions	- o CWA - o RCRA - o TSCA - o Hazardous and Solid Waste Amendments (HSWA); also known as RCRA Reauthorization - o Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) - o SARA

Table 1. Areas of concern addressed by Federal environmental regulations.

While all of the laws listed in Table 1 potentially may affect the day-to-day operations of a pipeline, only a few have the proven potential to have a significant operational or financial impact on companies with pipeline systems. The following paragraphs describe these most significant laws, and summarize their specific impacts on the pipeline industry.

NATIONAL ENVIRONMENTAL POLICY ACT (NEPA)

Synopsis: Signed into law on 1st January, 1970, NEPA represents the first attempt by Congress to define an environmental policy for the United States. The goal of NEPA was to develop practicable means to conduct federal activities that will promote the general welfare of, and be in harmony with, the environment.

The most significant provision of NEPA is contained in Section 102(2)(c). This provision requires that a detailed environmental impact statement (EIS) be prepared for every major federal action that may significantly affect the quality of the environment. In particular, the following issues must be addressed:

- the environmental impact of the proposed action;
- any adverse environmental effects which cannot be avoided should the proposed action be implemented;
- alternatives to the proposed action;
- the relationship between local short-term activities and long-term enhancement of productivity of man's environment; and
- any irreversible and irretrievable commitments of resources that would occur should the proposed action be implemented.

It is important to note that NEPA applies to federal agencies only, and that the EISs must be prepared only by the responsible federal agency. However, state and local agencies and private parties may assist or be required to assist the responsible federal agency. The final analysis of the data, as well as the conclusions reached, must be the responsibility of the appropriate federal agency.

The major impact of NEPA is not found within the procedural requirements for federal agencies, but rather in the fact that its passage has resulted in a new attitude and awareness toward environmental protection. NEPA

changed the way the nation viewed the environment and provided a general philosophy of environmental regulation. In addition, NEPA has acted as the foundation for virtually all subsequent environmental laws.

Impacts on the pipeline industry: NEPA's major impact on the pipeline industry stemmed from its requirement that federal agencies submit EISs for anything deemed a major federal action. This mandate forced the Federal Energy Regulation Commission (FERC) to require that the pipeline industry prepare environmental assessments for many of its large, interstate pipeline expansion projects. This FERC requirement caused added expenditures, as well as occasionally delaying or altering construction. However, NEPA's most significant impact was the requirement's strong focus of regulatory attention on the pipeline industry and its operations.

CLEAN WATER ACT (CWA)

Synopsis: CWA, enacted in 1972, mainly controls discharges of effluent from point sources into United States' waters. The act establishes national technology-based effluent standards with which all point source discharges are required to comply. The ultimate result of the act is to return all of the United States' surface waters to a quality suitable for fishing and swimming.

CWA regulations include standards for direct discharges, indirect discharges, sources that spill hazardous substances or oil, and discharges of dredged or filled material.

Facilities that directly discharge into navigable waters must obtain a National Pollutant Discharge Elimination System (NPDES) permit. This permit allows the applicant to discharge certain effluents, providing that the permit requirements are met. These requirements are based on the type of effluent, as well as national technology-based guidelines, and state water quality standards.

Discharges into municipal sewers are classified as indirect discharges and do not require a permit. However, the discharge of effluent into a publicly-owned treatment works (POTW) must comply with the pretreatment standards required by the POTW.

Section 311 of CWA is the common tie between CWA and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and has as its objective the elimination of oil and hazardous substance spills

into navigable waters. Section 311 also requires that certain facilities prepare Spill Prevention Control and Countermeasure (SPCC) plans to control oil pollution. In addition, Section 311 designates 300 substances that are hazardous if spilled or accidentally discharged into navigable waterways, and establishes the minimum substance amount (reportable quantity) that, when spilled, must be reported to the National Response Center.

CWA also regulates the discharge of dredged or fill material into United States' waters. CWA has given authority for enforcement of this portion of the act to the United States Army Corps of Engineers (COE).

CWA required the development of a plan designed to minimize damage from hazardous substances discharges. This plan is known as the National Oil and Hazardous Substances Contingency Plan (NCP). In short, this plan provides for the establishment of a national strike force that is trained to respond to spills and to mitigate effects on the environment.

Section 504 of CWA contains an imminent hazard provision, allowing EPA to require clean-up of sites that demonstrate an imminent and substantial endangerment to public health or the environment. This section is applicable to the control of point sources that discharge pollutants to navigable waters.

Impacts on the pipeline industry: CWA affects the pipeline industry primarily in three areas:

In many instances, pipeline construction that crosses navigable waterways requires a permit from COE. The permit generally stipulates that the crossing be accomplished using techniques that eliminate or minimize soil erosion and subsequent sedimentation of the water body.

Section 311 of CWA requires that any facility that stores oil (1,320galls or more above ground, or 42,000galls or more underground) must have an approved SPCC plan. Pipeline facilities that fit this description must have such a plan in place, and must meet any design requirements of the plan.

Section 311 also requires that, if applicable, pipeline facilities have in place a NPDES permit for any appropriate point source discharges. While the necessity for such a permit will vary from facility to facility, permits generally are required for any discharges originating from production or process areas, as well as floor drains located in compressor or pumping facility basements.

CLEAN AIR ACT (CAA)

Synopsis: CAA, enacted in 1970, is the successor to a number of acts whose goal was the reduction of airborne emissions and the general improvement in ambient air quality. The version of the act passed in 1970 included provisions for the establishment of National Ambient Air Quality Standards (NAAQS) which were designed to protect primary public health and secondary public welfare (i.e. the environment). In order to accomplish these goals, CAA required the United States Environmental Protection Agency (EPA) to identify air pollutants; set national air quality standards; formulate plans to control air pollutants; set standards for sources of air pollution; and set standards limiting the discharges of hazardous substances into the air. The last requirement, which establishes the National Emission Standards for Hazardous Air Pollutants (NESHAPs), applies to both new and existing sources of pollutants that pose a significant health hazard. CAA results in both direct and indirect control of toxic air pollutants.

NAAQS apply to sulphur oxides, particulates, nitrogen oxides, carbon monoxide, ozone, non-methane hydrocarbons, and lead. Hazardous air pollutants regulated by NESHAP include asbestos, beryllium, mercury, and vinyl chloride. NESHAP-regulated pollutants differ from NAAQS-regulated pollutants, in that NESHAP pollutants usually are localized and can be technically difficult and costly to control.

In 1990, the United States Congress passed a sweeping Clean Air Bill which will require even more stringent limitations of the emission of pollutants to the atmosphere.

Impacts on the pipeline industry: CAA has had many significant impacts on the pipeline industry, since most processes associated with hydrocarbon development and pipeline operations result in some sort of potentially regulated emission. In particular, the operation of pumping or natural gas compressor facilities generally requires permits that control the amount of emissions. While the emissions generated by these facilities generally are limited to the products of combustion of hydrocarbon fuels, pollution control devices required to limit these emissions can be quite expensive. In addition, recent developments have shown that regulatory agencies are becoming more aware of fugitive releases of processed hydrocarbons.

CAA historically may not have affected the pipeline industry to the same degree as some other environmental laws. However, it is likely that with the passage of the 1990 bill, the control of air pollutants will become a much greater priority on the agenda of regulators and the general population.

COMPREHENSIVE ENVIRONMENTAL RESPONSE, COMPENSATION, AND LIABILITY ACT OF 1980 (CERCLA)

Synopsis: CERCLA was designed to provide a response for the immediate clean-up of hazardous substance contamination resulting from accidental or non-permitted releases or from abandoned waste disposal sites. The goal of CERCLA is to require those parties responsible for a non-permitted release to pay for the clean-up of that release. If the responsible party cannot be identified quickly enough to address an imminent and substantial endangerment, the federal government will respond. If a settlement cannot be reached with the responsible party, the federal government also will take action and seek to recover - from the responsible party - the cost of the release.

NCP contained in CWA was revised by CERCLA. It was revised to include methods for identifying facilities at which hazardous substances have been disposed; methods for evaluating and remedying releases of hazardous substances and for analysis of relative costs; methods and criteria for determining the appropriate extent of clean-up; methods for determining federal, state, and local roles; and a means of assuring the cost-effectiveness of remedial actions.

CERCLA provides for the establishment of a National Priorities List (NPL) of abandoned waste sites that present the greatest danger to public health and the environment. The list is established by EPA in CERCLA Section 105(a)(8). Using the Hazard Ranking System, the sites on the list are ranked according to their potential threat to human health and the environment. In theory, those sites scoring highest under this system are deemed to possess the greatest environmental threat and therefore will be addressed first.

All responses taken under CERCLA by the federal government, state government, or responsible party must follow the investigative and remedial procedures set forth in NCP, which is the central regulation outlining response authority and responsibilities under CERCLA.

Impacts on the pipeline industry: Because the thrust of CERCLA is directed toward abandoned waste sites, CERCLA generally has had little impact on actively-operating pipeline facilities. However, there have been numerous instances where members of the pipeline industry have had to pay for the clean-up of waste sites that received waste products from the pipeline company. Unfortunately, when multiple companies have dumped waste products at a site that is undergoing a CERCLA-derived investigation and

remediation, it is very difficult to identify the portion of the waste put in by any one entity. In such instances, pipeline companies sometimes are believed to have "deep pockets" and may be asked to pay more than their fair share toward any clean-up activities.

CERCLA also may play a role at abandoned or surplus facilities which, due to the presence of some hazardous substance, may be deemed as NPL sites. Historically, instances of the pipeline industry's involvement in this situation are rare; however, abandoned manufactured gas plants and hydrocarbon processing plants are beginning to attract the attention of CERCLA regulators.

EPA also has used the imminent and substantial endangerment provision of CERCLA to address situations that fall outside the scope of other environmental laws. EPA frequently has invoked this provision of CERCLA in dealing with pipeline companies faced with historic polychlorinated biphenyl (PCB) contamination. By using this provision of CERCLA as a "catch-all" category, EPA has had jurisdiction in many instances in which its authority under other laws could be questioned.

RESOURCE CONSERVATION AND RECOVERY ACT (RCRA)

Synopsis: RCRA regulates the handling of hazardous waste at actively-operating facilities, and is intended to provide for the environmentally-sound disposal of waste materials. RCRA, in part, was developed to address those wastes generated as the result of CWA and CAA passage.

During the early 1970s, much attention was given to removing contaminants from air and water discharges and disposing of these contaminants as solid wastes. Unfortunately, many of these contaminants removed from air or water disposal were improperly disposed, and seeped back into the environment. It was determined that the improper disposal of these waste products - as well as the disposal of other non-regulated waste products - was resulting in a great deal of environmental damage.

RCRA was passed on 21st October, 1976, replacing the Solid Waste Disposal Act. It took EPA nearly six years to develop a near-complete set of regulations and, as promulgated today, RCRA is one of the nation's largest and most controversial regulatory programmes.

Subtitle C of RCRA addresses:

Environmental considerations and risk assessment

classification of wastes and hazardous waste;
cradle-to-grave manifest system, record keeping, and reporting requirements;
standards for generators, transporters, and facilities which treat, store, or dispose of hazardous waste;
enforcement of the standards through a permitting program and civil penalty policies; and
the authorization of state programs to operate *in lieu* of the federal programmes.

Subtitle D of RCRA addresses the disposal of non-hazardous solid waste. This part of RCRA generally is enforced by individual states. Other than publishing criteria for sanitary landfills and maintaining an inventory of open permitted dumps, EPA has little to do with the regulation of non-hazardous solid waste disposal.

RCRA was amended in 1984, and the scope of the act was widely broadened. Additional restrictions on land disposal, small quantity generators, burning and blending of wastes, underground storage tanks, interim status facilities, inspections, and civil suits were addressed in the 1984 amendments. The new law added 72 provisions to RCRA and was designed to fill in the gaps or apparent regulatory loopholes of the 1976 version.

Impacts on the pipeline industry: Of all the environmental laws passed to date, RCRA probably has had the most lasting effect on the pipeline industry. This rating is because, with very few exceptions, pipeline facilities fall under the classification of generators of hazardous wastes; as such, these facilities are subject to the generator standards' provisions of RCRA. Under RCRA, a generator is any entity whose act or process produces a hazardous waste, or whose act first causes a hazardous waste to become subject to regulation. Although it is not unlawful to generate hazardous waste, a generator is required to fulfil a number of requirements, including making an effort to reduce the quantity of hazardous waste generated. In addition to the requirement that the generator reduce the amount of waste, the generator must have an EPA identification number and must assure that wastes are shipped in proper containers, accurately labelled, and accompanied with proper placards for use by the transporter. Generators further are required to ship the wastes off-site within 90 days after the initial date of accumulation. If they do not do so, they must have a storage permit.

Generators also must comply with applicable storage standards for containers; conduct proper operating, maintenance, and inspection procedures;

conduct personnel training; and prepare a contingency plan to be followed in the event of an emergency. Table 2 presents generator requirements applicable to the pipeline industry.

Members of the pipeline industry that historically disposed of waste products on property currently occupied by an operating facility may come under RCRA authority. Because these facilities are not abandoned, they do not come under the authority of CERCLA, but rather under RCRA. In many instances, pipeline facilities that disposed of waste products on-site have been forced by RCRA regulations to initiate expensive remedial activities. Facilities such as on-site pits that received hydrocarbons as a result of pigging activities have been targeted by the regulatory agencies for close inspection of their applicability to RCRA regulation.

TOXIC SUBSTANCES CONTROL ACT (TSCA)

Synopsis: While RCRA has had the most lasting effects on the pipeline industry, TSCA has had the most acute impact. Passed in 1976, TSCA was the culmination of five years of intensive effort by Congress to provide a regulatory framework for comprehensively dealing with risks posed by the manufacture and use of chemical substances. The force behind the passage of TSCA was repeated incidents involving environmental damage and adverse health effects resulting from the widespread use of substances such as PCBs, kepone, vinyl chloride, polybrominated biphenyls, and asbestos. TSCA was designed to regulate the manufacture and distribution of existing and new chemical substances, and therefore applies primarily to on-going chemical manufacturing operations and their products.

As in the case of RCRA, TSCA was an indirect development of the passage of CWA and CAA. These acts heightened the nation's general awareness of the apparent widespread contamination of toxic compounds. However CAA, CWA, and RCRA had authority to deal with toxics only after they had entered the environment as wastes. Federal and state authority to regulate toxics before they became waste products was limited. TSCA was designed to deal with toxics in the manufacturing and distribution stage, before human or environmental exposure.

TSCA regulates the safety of raw materials. TSCA's two main regulatory goals include obtaining data from industry regarding the production, use, and health effects of chemical substances and mixtures; and regulating the manufacture, processing, and distribution in commerce, as well as use and disposal of a chemical substance or mixture. These goals are achieved

Environmental considerations and risk assessment

- o Notification of EPA
- o Obtainment of Identification Numbers
- o Utilization of the Manifest System;
- o Observation of Proper Waste Packaging Procedures
- o Shipment of Wastes to Permitted Treatment, Storage, or Disposal Facilities
- o Preparation of Annual Reports
- o Storage of Wastes On-Site Less than 90 Days
- o Preparation of Training and Contingency Plans.

Table 2. Generator requirements applicable to the pipeline industry.

through screening new chemicals, testing chemicals identified as potential hazards, gathering information on existing chemicals, and controlling chemicals proven to pose a hazard.

Section 6 of TSCA provides the federal government with the authority to control or ban substances that pose an unreasonable risk to health and the environment. While EPA currently regulates a number of substances fitting this definition, the regulation of asbestos and PCBs have had the most impact.

The regulation of PCBs represents the full extent of powers granted to EPA under TSCA. Nowhere else in environmental statutes is any substance banned by name. In addition, what started out to be a rather simple manufacturing and use ban has developed into a complex set of regulations restricting PCB use; requiring inspections, reporting, and record keeping; establishing labelling and marking requirements; and outlining disposal requirements.

On 2nd April, 1987, EPA recognized the confusion surrounding the requirements for cleaning up PCB spills and passed a PCB Spill Cleanup Policy (40 CFR 761.120-135). This policy established a national spill clean-up policy, and requires notification of PCB spills into sensitive areas and for all spills

greater than 10lbs. The policy also establishes clean-up levels and general methodologies for spills onto both solid surfaces and soils.

Impacts on the pipeline industry: In many instances, the regulation of PCBs by TSCA has had a major financial impact on members of the pipeline industry. Historically, PCBs have been used widely as heat exchange fluids and lubricants, both by natural gas pipelines and by product pipelines. In natural gas pipelines, this use of PCBs has led to the contamination of compressor facilities as well as the pipelines. The TSCA-required clean-up of this contamination has been estimated to have the potential to cost one natural gas transmission system more than \$500million. Natural gas transmission companies recently have begun to address the problem of historic PCB contamination; although the magnitude of financial liability has not been determined accurately by these companies at this time, early estimates indicate that the clean-up of PCB contamination potentially will be expensive.

The selected level of clean-up for PCBs has not been totally agreed upon by all regulatory agencies. However, the utilization of risk assessment as a tool to set clean-up levels is becoming more popular throughout the industry and regulatory community. It is hoped that by the effective use of risk assessment, clean-up levels can be established based on a realistic determination of the risks posed.

OTHER ENVIRONMENTAL REGULATIONS

There are numerous other environmental regulations that could have an impact on the pipeline industry. Most notably, the Emergency Planning and Community Right-to-Know Act of 1986 could affect the pipeline industry. Other legislation regulating underground storage tanks and pesticides also may have potential impacts.

It is assumed that the future will bring more environmental regulations to bear on the pipeline industry. The impact that these regulations have on the industry will be reduced significantly if pipeline industry representatives remain up-to-date on the regulations' contents and implications. The nation and the regulatory agencies now are looking to the pipeline industry not only as a source of hydrocarbon-based energy, but as an industry that conducts its business in an environmentally-responsible manner.

PART 2

OPERATIONAL EXPERIENCE

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A COMPUTERIZED INSPECTION SYSTEM FOR PIPELINES

INTRODUCTION

This paper describes Total Oil Marine's computerized inspection system for pipelines (CIS-PIPELINE), which was developed by Scicon and successfully implemented in August, 1986.

The paper first discusses Total Oil Marine's philosophy for pipeline inspection and why the decision was taken to develop a computerized system. It identifies the requirements and highlights the expectations. An overview of the system is given with samples of the reports and analyses available. This is followed by a discussion of how the system met the expectations and the additional benefits which have come from use of the system.

BACKGROUND

Total Oil Marine's pipeline inspection activities

As operator of the *Frigg* Gas Transportation System, Total Oil Marine (TOM) has the responsibility for running two parallel 32-in subsea pipelines, each 362km long, between the *Frigg* field and the shore terminal at St. Fergus in the NE of Scotland.

The recent development of the *North Alwyn* field has added a further 110-km, 24-in gas line from *North Alwyn* to *Frigg*, a 15-km, 12-in oil line from *North Alwyn* to *Ninian* and a number of flow lines on the *Alwyn* field.

The principal objectives of the inspection programme are to ensure that pipelines are at all times in a safe operating condition and meet statutory

requirements from the UK Department of Energy and Norwegian Petroleum Directorate.

Three methods of inspection are used on the submarine sections of the pipelines:

Acoustic survey by side-scan sonar: This method allows an overall general inspection of the pipelines. It provides information on the trench and burial condition of the lines, detects significant changes on free spans (sections where the pipeline is not supported by the sea bed) and identifies areas where the sea bed has been disturbed (anchor scars, etc.).

Because of the relatively-low cost per km and the speed of the method, the whole length of each pipeline is surveyed acoustically once a year.

Inspection by remote operated vehicle (ROV): This method allows a close detailed inspection on specific areas of the pipelines. Its main objectives are: to inspect the external condition of the pipeline, including its coatings and features (anodes, supports, etc.); to monitor the level of cathodic protection; to provide further and more accurate information on free spans and burial condition; and finally to detect the presence of debris (anchors, fish nets, etc.).

Due to the high cost per km and the slowness of this method, only specific areas of the lines are inspected each year. The inspection scope is defined so that all non-buried areas are surveyed at least once in a five-year cycle. Any significant free spans detected by the latest acoustic inspection are included in the next ROV inspection.

Internal inspection by intelligent pigging: This method allows a full assessment of the pipe wall condition along the whole length of the line (including risers). It detects anomalies in the pipe geometry (ID restrictions) and the pipe wall (corrosion, etc.). The *Frigg* pipelines are inspected by intelligent pig once every four years.

Acoustic and ROV surveys are used in conjunction, as the results provided by the acoustic inspection, normally carried out during spring, are used to define the scope of the ROV campaign which takes place during summer. Any remedial action required will be decided during or after the ROV survey and will normally be carried out in autumn.

As a consequence, two critical periods for result analysis can be identified:

- after the acoustic campaign, when the scope of the ROV inspection has to be finalized;
- after the ROV campaign, to plan the remedial action required.

Problems with the manual system

In 1985, after eight years of operation of the *Frigg* Gas Transportation System, pipeline engineers had increasing difficulties in accessing information and performing analyses on the available pipeline inspection data.

Some of the reasons behind these difficulties were as follows:

(1) The volume of inspection data collected since the commissioning of the pipelines was huge and increasing rapidly. This was due in part to improving techniques providing more data and additionally, as many inspection contractors became computerized, they were able to supply a greater variety of reports, e.g. the 1986 campaign on *Frigg* lines produced 4 volumes of Acoustic Reports and 18 volumes of ROV Reports (a volume being a 4-in A4 ring binder).

(2) The format and contents of reports were not conducive to post-analysis, being often based on operational considerations such as: dive references, direction of survey, etc.

(3) ROV surveys, as already mentioned, are only carried out on specific areas. As a consequence, a lot of effort is required to compile an inspection "history", to cross reference results and derive trends.

Reasons for considering computerization

Primarily, it was considered that computerization would overcome most of the difficulties mentioned, or at least reduce their impact, and at the same time provide additional advantages.

However, bearing in mind the large amount of data and the critical timescales of the campaigns, a pre-requisite of the system was to minimize the data input effort by capturing data in computer form, e.g. magnetic tapes or other types of interface for direct loading to the database. Indeed, inputting data manually would have certainly defeated the purpose of the computerization, which was to reduce the amount of work.

This meant that the inspection contractors had to be computerized themselves. In fact, by 1985, the majority of them were already using computers:

Offshore - automatically to capture positioning and inspection data such as UTM co-ordinates, kilometre posts, CP potential and sea bed profile.

Onshore - to process this data in order to produce reports for clients.

Possible options

Turnkey vs. bespoke system

The first decision to be taken was whether to buy an existing system or to develop a new one based on TOM's requirements. In 1985, there were not many computerized pipeline inspection systems on the market, and none of the existing ones really met the requirements. It was for this reason that TOM decided to opt for a bespoke system.

Onshore vs. offshore

Secondly it was necessary to determine whether the system would be taken on-board the inspection vessels during the campaigns or would remain onshore.

In favour of the "offshore" option were: the ability to access the database during the survey and the possibility of realtime data input. Against this idea were: the concern of added complexity and the requirement for more personnel, which would increase the cost of the inspection.

However, it was noted that there was no real need to access the database during the survey if the operation was properly prepared. Therefore the decision was made that the computer would remain onshore and inspection data would be loaded from magnetic tapes shortly after the campaigns.

Microcomputer vs. minicomputer or mainframe

The last decision was to choose the type of machine the system would run on.

The points in favour of a microcomputer (inexpensive hardware and system software, simplicity of operation) were outweighed by the advantages of using a bigger machine, for which the hardware and system software would be more appropriate to the volume of data to be managed. Additionally, it would provide a multi-user environment and there would be less chance of hardware or software being phased out a few years later.

For this application, which was a long-term investment, a minicomputer was considered to be a better choice than a micro. Company policy for information systems and computer availability then dictated that the system would be developed on a PRIME computer.

System development

Following the previous decisions, a functional specification was prepared by TOM and issued as part of the call for tender for the development and implementation of CIS-PIPELINE.

Scicon Ltd was awarded the contract. The system was developed between September, 1985, and August, 1986.

SCOPE OF THE SYSTEM

Requirements

The data held for each pipeline is in three main categories:

- construction and environmental data;
- inspection data covering acoustic, ROV and internal inspections;
- maintenance data.

The requirements of the system are:

- to support batch input of a large amount of data supplied by the inspection contractors on magnetic tapes;
- to support interactive input/update of information;
- to support interactive enquiries/reports on the information held;
- to support detailed analyses of data from both past and present inspections;
- to provide data for graphical output, either to the screen or a plotter, for some of the reports and analyses.

Expectations

The following points were considered to be the major advantages likely to result from the computerization, thus justifying the development cost.

(a) *Improvement of the awareness of the pipeline condition*: By allowing the results from previous and current inspections to be easily accessed, summarized and compared (from one campaign to another or from one method to another) the computerization would improve TOM's knowledge

of the pipeline condition. The engineers would be able to better understand any changes in this condition, thus enabling them to take the necessary action. Increased safety would therefore be a major benefit of using the system.

(b) *Shortening of response time in finding information*: Because all the data would be concentrated in one place, and furthermore in a database, it would take the engineer less time to find it in comparison to searching through the reports. This is especially true for occasions where several campaigns are involved, for example, free-span history. More efficient use of the engineer's time would therefore be made when analysing the data.

(c) *More cost-effective scope of ROV inspection*: The preparation of the ROV inspection scope is a long and tedious process when carried out manually. Priority is given to areas which have not been surveyed recently or which have a high risk of problems. The difficulty comes from the information being scattered in many reports and from constant changes in the pipeline condition. A program based on an algorithm would carry out this task systematically and efficiently. A recommended scope would then be presented to the engineer who had the ultimate responsibility for the final decision. Consequently, a reduction of engineer time would be achieved as well as a more refined scope of work.

(d) *Reduction of the number of reports*: As most of the data would be transmitted via magnetic tapes, the number of reports provided by the contractors could be reduced, particularly those readily produced on demand from the system.

THE SYSTEM

Data overview

The database is composed of three main areas as described below. In addition a master record is stored for each pipeline to hold such details as pipeline name, total length, etc. (see Fig.1 for database diagram).

Much of this information is classified and accessed using the kilometre post (or Point kilometrique, PK) value giving the distance of any point along the line from the defined base co-ordinates of the pipeline.

A computerized inspection system

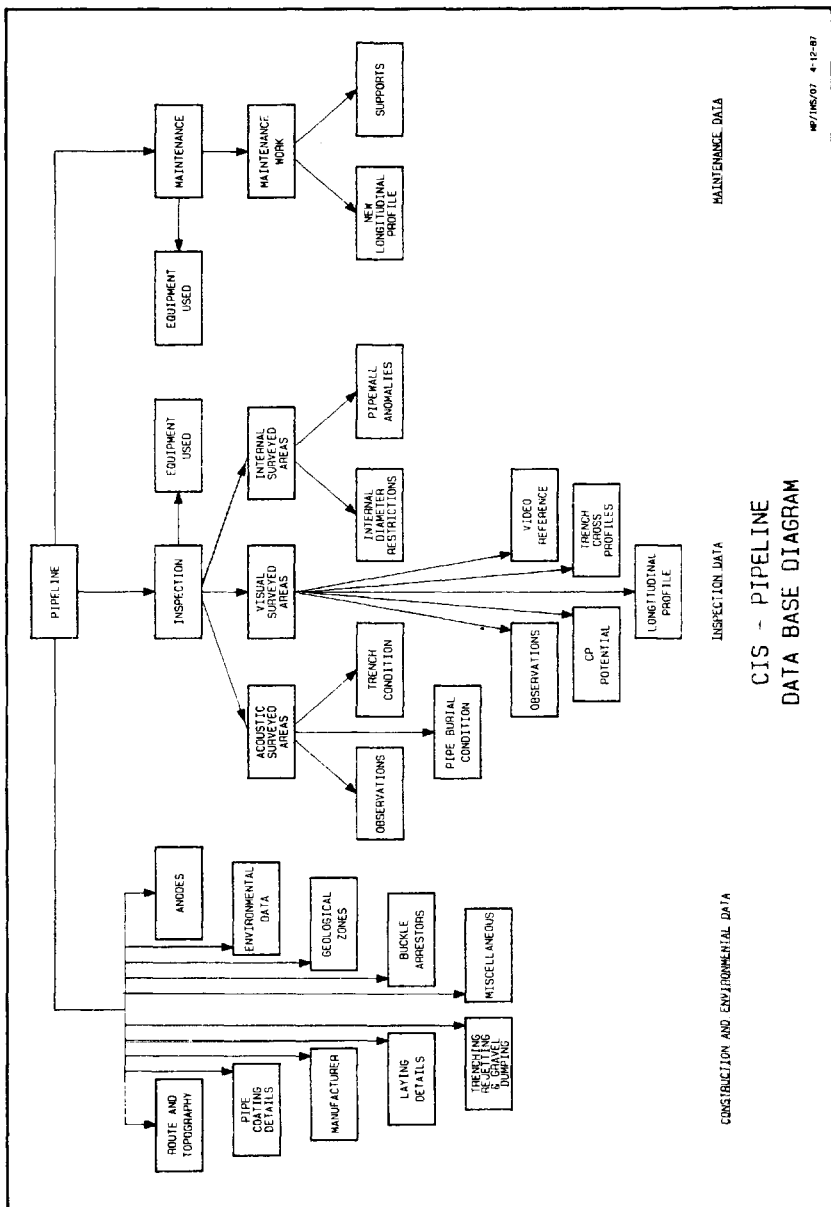


Fig.1. Database diagram.

Construction and environmental data

This information, added retrospectively, is maintained manually and allows the system to validate inspection data and to prepare analysis sheets with all relevant pipeline information. It is however not intended to hold a complete history of the pipeline construction in this category. The following information is held for each pipeline:

- pipe route (UTM co-ordinates, water depths);
- physical characteristics (wall thickness, coatings, features such as anodes, etc.);
- construction data (manufacturer, laying, trenching, etc.);
- environment (sea currents, waves, etc.).

Inspection data

The inspection details, for each pipeline, are held in a hierarchy of records linked to the main pipeline record. The general details of the inspection, such as: scope of inspection, dates, contractor, etc., are held in the inspection record. Then, depending on the type of inspection, further details are held in a variety of subordinate records.

Acoustic inspection results:

- pipe burial and trench condition;
- observations: free spans, scars on sea bed.

ROV inspection results:

- observations: damage, anode condition, free spans ...
- longitudinal and transverse trench profiles;
- cathodic protection level;
- videotape references.

Internal inspection results:

- internal diameter restrictions;
- pipe wall anomalies

Some analysis functions (such as suspension history) allow the characteristics of an observation (length, height, etc.) to be compared over the years. Because of the inaccuracy inherent in all pipeline positioning systems, the PK value supplied by the inspection contractor will not exactly match those of previous inspections. By comparing the observations it is possible addition-

A computerized inspection system

ally to assign a correlated PK value to the observation which links the same event over a number of inspections.

Maintenance data

The following information is held for each maintenance activity that is carried out on each pipeline:

- details on scope of maintenance, dates, contractor and equipment used;
- description of work performed.

In particular for grout-bagging operations the following additional information is stored:

- details of supports;
- longitudinal profile of free span after stabilization.

System design objectives

The major design objectives for CIS-PIPELINE were as follows:

(i) To store and maintain large quantities of data in a form which facilitates easy access

The system enhances the storage, retrieval and analysis of inspection data gathered during the annual inspection of the pipelines. It supports batch input, from magnetic tape, of data provided by the inspection contractors, as well as facilities interactively to enter and amend any data item held on the database from one of the terminals.

(ii) To provide a system which would offer significant support to users who are non-computing professionals

The system gives users access to functions via a series of menus. All screen displays used in the system have standard header and trailer areas. These give: basic identifying data (screen reference, pipeline name, functional category, etc.), indicate the functions keys available and a line is reserved for messages. Help facilities are available to assist in the selection of valid codes for library

items, e.g. observations. The user moves between screens using the function keys.

(iii) To incorporate as much flexibility as possible into the design

Several categories of data are implemented in library form, to avoid data duplication, provide searching facilities and to allow for the possibility of extending data types. Example: anode type library, inspection equipment library.

A system-parameter library holds details such as terminal and output device characteristics, to accommodate future requirements, and parameter values used by a number of functions (scaling details, etc.).

A parameter-driven library was designed in order to hold observations made during surveys (e.g. SU: suspensions) and their parameters (e.g. length, height). In this way, new observations and parameters can easily be added by the users.

(iv) To provide adequate security restrictions for the system

It is important to protect the data from unauthorized use. Access to the system is based on each user having a unique user identification and password. Access to a specific category of functions is restricted by the user's security classification. On logging onto the system, the user is presented with a menu of the available categories based on his classification. To provide a secure system it is important that users remember to log off at the end of each session and also not to leave a logged-on terminal unattended. To minimize the possibility of a breach in security, a timeout facility is incorporated into the system, so that any terminal which has had no activity for a given period of time is automatically logged off.

System functions

There are five categories of functions available on the system. Each user has access to one or more of these depending on their security classification.

Interactive editing

The functions available in this category are used to input or amend any item of information held on the database. The data entered is validated against the

A computerized inspection system

information already held to ensure it is consistent. Users are also able to delete a particular occurrence of a record type but the option to delete a complete hierarchy of records (e.g. in inspection) is limited to the database maintenance category.

Bulk loading

Functions are available to bulk load nearly all of the inspection results automatically, from magnetic tape, thus reducing manual input to a minimum. The tapes are completed offshore during the surveys, or shortly after, by the inspection contractors. The format of the tapes has been designed to accommodate the requirements of this system and the standard working procedures of contractors.

The following data can be "bulk" loaded: acoustic inspection, incorporating pipe burial condition, trench condition and observations; ROV inspection, incorporating observations, longitudinal profile, transverse profiles, and CP potential.

Reporting

A number of reports are available either for display at the terminal or output to the printer. On choosing the report required, the user is prompted to enter the selection criteria and the output device. Selection criteria can be such as: a range of PKs, particular type of observation, dates, etc.

There are printed reports available for any data held on the database, such as list of inspections, list of observations (Fig.2).

In addition, some graphical reports are available which correspond to the visual charts used in pipeline inspection such as: ROV alignment sheet (Fig.3), acoustic summary sheet, free span drawing.

Analysis

A number of analyses can be requested which allow the results of several inspections to be processed.

The results from all inspections performed to date can be merged in summary charts providing the latest information available at any point of the pipeline. Summary charts available include:

- pipe burial condition (Fig.4);
- summary of observations (Fig.5);

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TOTAL OIL MARINE PLC		LINE: FRIGG LINE 1 NORTH TP1-MCP01	CIS PIPELINE	
REF: R340		Visual Inspection : Observations	07/12/87 PAGE 2	
Inspection Reference : UI-1987				
PK (Km)		Observations and Parameters	Photo Refs.	
Actual	Correlated		From	To
175.171	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 10 CM		
		BREADTH : 3 % CIRCUM		
		POSITION OF DAMAGE : RIGHT(SIDE B)		
178.897	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 10 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		
178.900	0.000	CONCRETE COATING DAMAGE	12/001	
		SEVERITY : MEDIUM		
		LENGTH : 30 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		
178.926	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 20 CM		
		BREADTH : 6 % CIRCUM		
		POSITION OF DAMAGE : RIGHT(SIDE B)		
178.964	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 5 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		
178.985	0.000	CONCRETE COATING DAMAGE	12/002	
		SEVERITY : MEDIUM		
		LENGTH : 15 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		
179.014	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 10 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		
179.023	0.000	CONCRETE COATING DAMAGE		
		SEVERITY : LIGHT		
		LENGTH : 10 CM		
		BREADTH : 100 % CIRCUM		
		POSITION OF DAMAGE : LEFT(SIDE A)		

Fig.2. Typical list of observations.



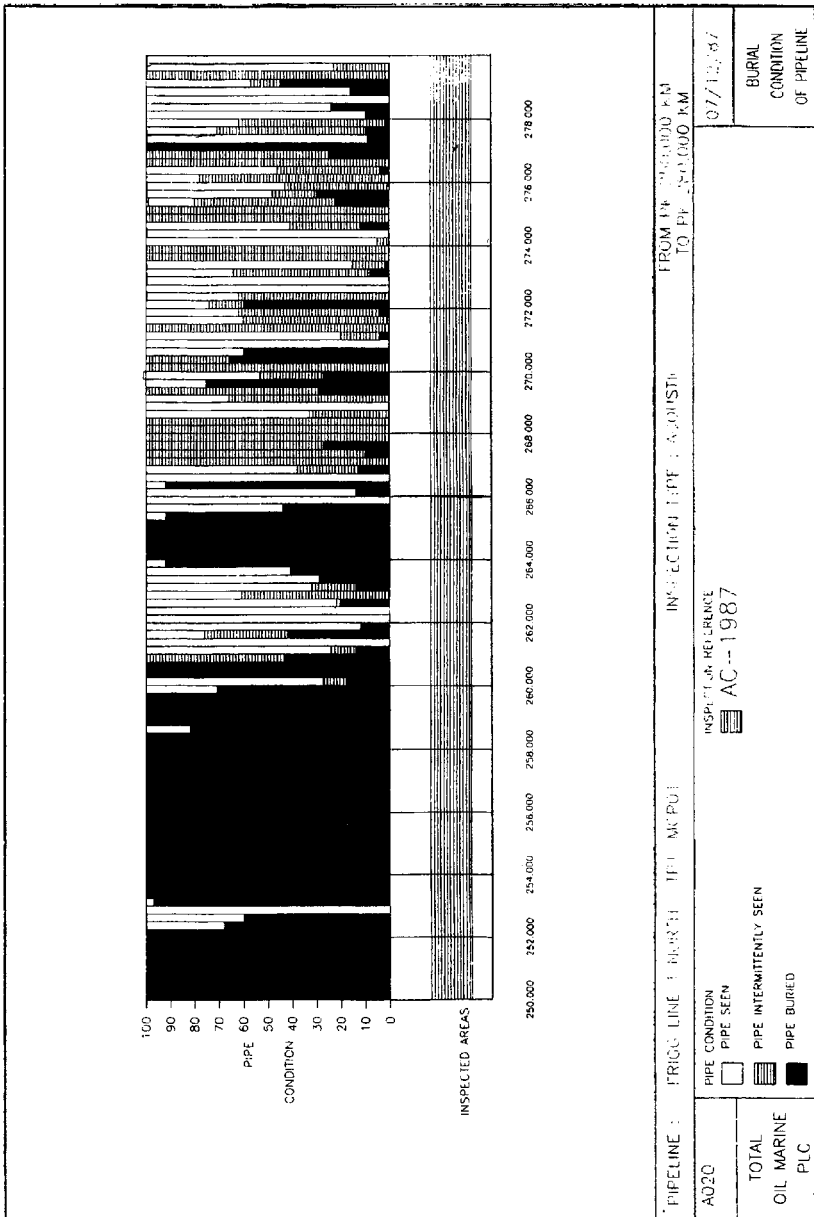


Fig.4. Pipe burial condition chart.

A computerized inspection system

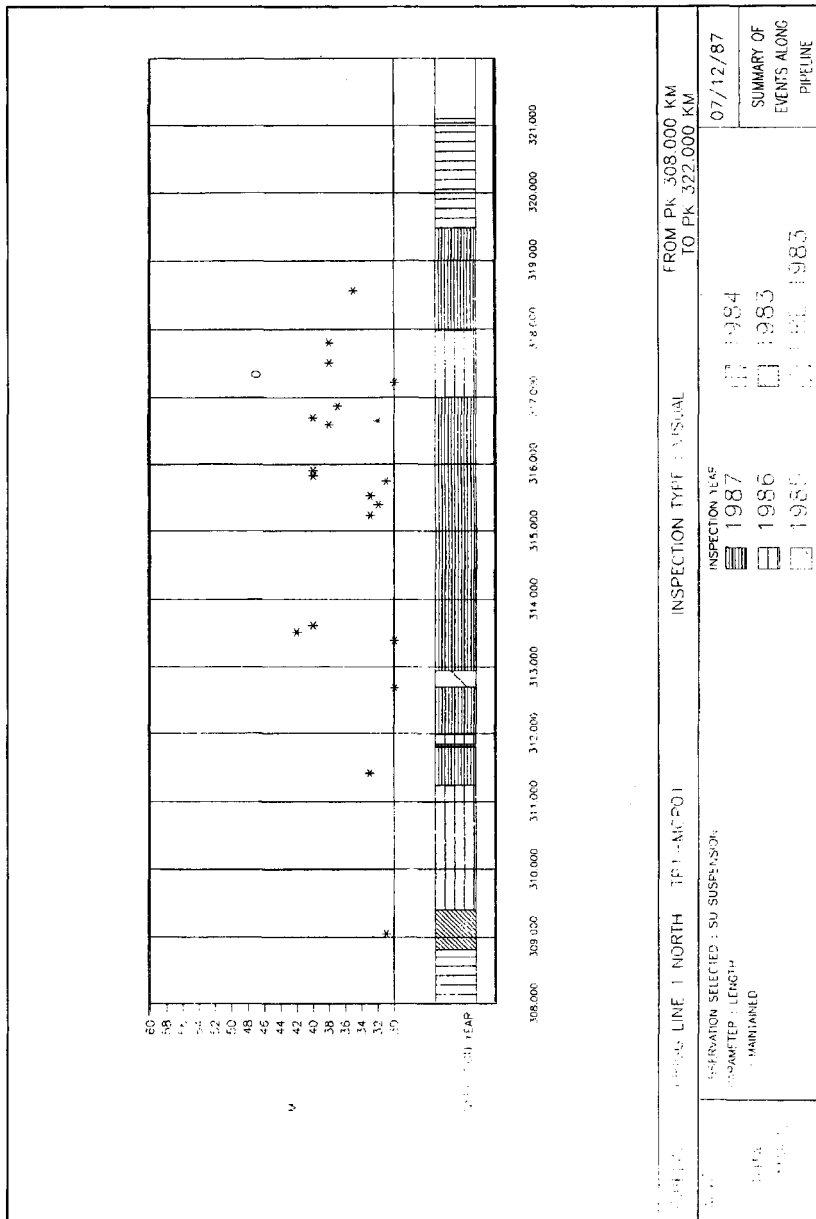


Fig.5. Observation summary chart.

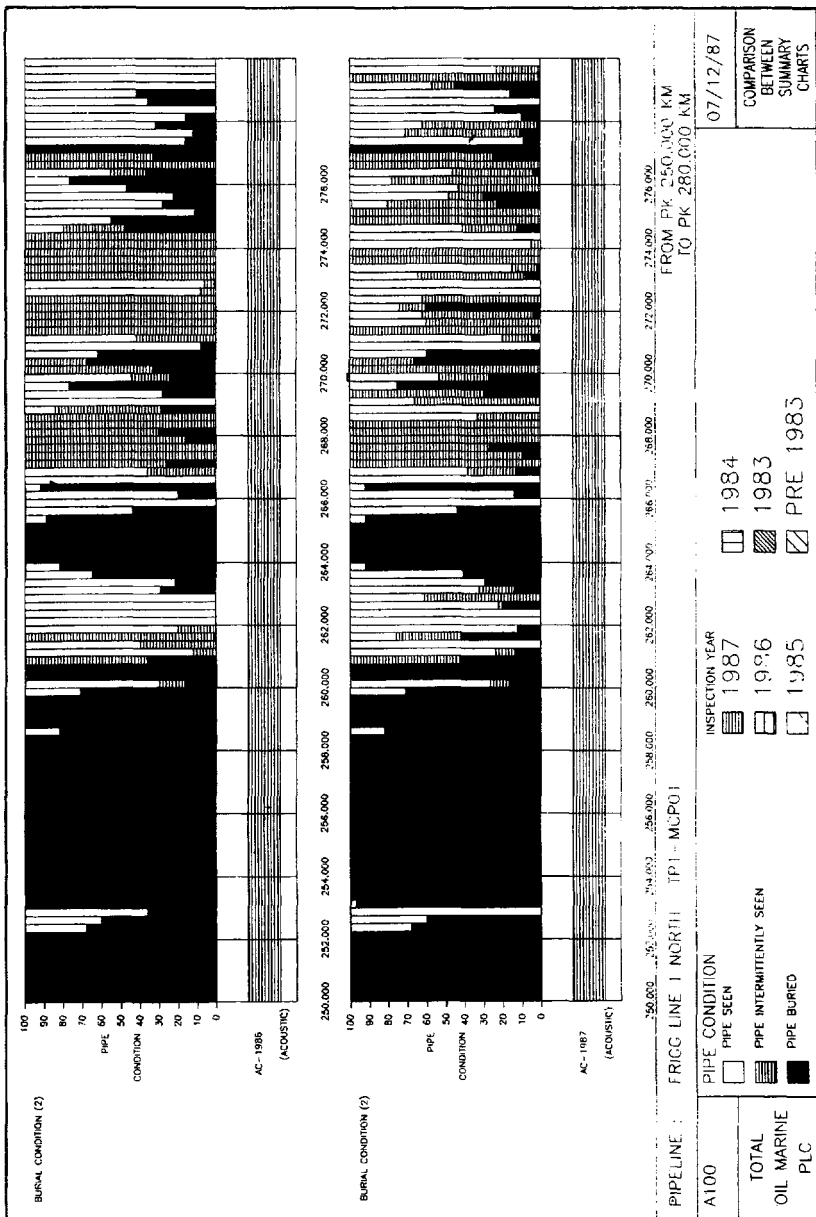


Fig.6. Summary chart comparison.

A computerized inspection system

TOTAL		LINE: FRIGG LINE 1 NORTH TP1-MCP01						CIS					
OIL MARINE PLC		Suspension History						PIPELINE					
REF: A200								07/12/87					
PAGE 1													
Selection - PK Range (Km) : 174.709 To 226.000													
Year Range : 1981 To 1986													
'X' : Not surveyed '-' : Surveyed, but no suspension found													
YEARS	1981		1982		1983		1984		1985		1986		Stab
PK (Km)	L	H	L	H	L	H	L	H	L	H	L	H	Year
174.740	-	-	-	-	-	-	30	1.0	45	1.0	9	1.0	1985
174.748	-	-	-	-	-	-	-	-	X	X	32	0.2	
175.029	-	-	-	-	-	-	-	-	-	-	12	0.0	
175.195	-	-	-	-	-	-	-	-	-	-	17	0.0	
175.312	-	-	-	-	26	1.0	51	1.2	19	1.3	58	1.0	1986
178.860	28	0.3	-	-	-	-	X	X	X	X	X	X	
179.297	-	-	-	-	X	X	X	X	X	X	12	0.0	
179.349	-	-	-	-	X	X	X	X	X	X	10	0.0	
179.385	-	-	-	-	X	X	X	X	X	X	11	0.0	
179.763	-	-	X	X	X	X	X	X	12	0.2	X	X	
180.820	X	X	X	X	X	X	X	X	14	0.1	X	X	
180.875	X	X	X	X	X	X	X	X	20	0.0	X	X	
183.417	X	X	X	X	X	X	X	X	10	0.3	X	X	
188.203	X	X	X	X	X	X	X	X	15	0.1	X	X	
189.224	X	X	X	X	X	X	X	X	13	0.0	X	X	
189.704	X	X	X	X	X	X	X	X	11	0.1	X	X	
190.007	X	X	X	X	X	X	X	X	11	0.1	X	X	
195.586	X	X	-	-	-	-	-	-	X	X	24	0.1	
195.618	X	X	-	-	-	-	-	-	X	X	14	0.1	
195.653	X	X	-	-	-	-	-	-	X	X	14	0.2	
195.679	X	X	34	0.3	47	0.3	48	0.3	X	X	19	0.3	1983
195.686	X	X	-	-	-	-	-	-	X	X	11	0.2	
195.737	X	X	-	-	-	-	-	-	X	X	13	0.2	
195.765	X	X	-	-	-	-	-	-	X	X	15	0.1	
195.793	X	X	-	-	-	-	-	-	X	X	32	0.1	
195.799	X	X	25	0.3	0	0.0	79	0.3	X	X	-	-	
196.427	X	X	-	-	25	0.3	X	X	X	X	24	0.3	
196.749	-	-	27	0.3	26	0.3	X	X	X	X	20	0.2	
196.781	-	-	-	-	-	-	X	X	X	X	19	0.2	
196.799	-	-	-	-	-	-	X	X	X	X	14	0.2	
196.800	37	0.3	55	0.4	28	0.3	X	X	X	X	32	0.1	1982
196.887	-	-	-	-	39	0.3	X	X	X	X	40	0.3	
196.900	-	-	-	-	-	-	X	X	X	X	27	0.2	
196.924	-	-	-	-	-	-	X	X	X	X	14	0.1	
196.994	-	-	44	0.3	0	0.0	X	X	X	X	46	0.3	
197.005	-	-	-	-	-	-	X	X	X	X	24	0.3	
197.028	-	-	-	-	-	-	X	X	X	X	20	0.3	
197.047	-	-	-	-	-	-	X	X	X	X	16	0.2	
197.070	35	0.3	30	0.3	0	0.0	X	X	X	X	25	0.3	
197.684	X	X	-	-	X	X	X	X	X	X	16	0.1	
197.712	X	X	-	-	X	X	-	-	X	X	13	0.1	
219.977	X	X	X	X	X	X	33	0.3	X	X	X	X	
225.092	X	X	X	X	X	X	-	-	X	X	38	0.2	
225.168	X	X	X	X	X	X	-	-	X	X	40	0.1	
225.306	X	X	X	X	X	X	-	-	X	X	27	0.2	
225.447	X	X	X	X	X	X	-	-	X	X	27	0.6	
225.530	X	X	X	X	X	X	-	-	X	X	14	0.0	

Fig.7. Suspension history.

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- summary of CP potential;
- summary of pipe-wall anomalies (revealed by internal inspection).

In addition, results from different campaigns or from different inspection types can be presented on a comparison chart. Comparison charts available include:

- comparison between summary charts (Fig.6);
- comparison between ROV and/or acoustic alignment sheet;
- suspension history (Fig.7).

Those programs can require a longer processing period; therefore to avoid locking the users terminals they can be run as background tasks, the results being sent to either the printer or a plotter, or kept in a file. In this way the user is able to continue using the terminal for other functions while the analysis is being carried out.

Database maintenance

This category of function has the highest security classification on the system as it contains the functions used to maintain the integrity and flexibility of the database. It is the only category which allows users to delete a complete hierarchy of data items, e.g. a pipeline or a complete inspection.

Users in this category are responsible for maintaining the libraries and for allocating system parameters and security classifications.

System software selection

Prime being the selected computer hardware it was therefore desirable to select Prime Systems' software if this could meet the needs of CIS-PIPELINE. This would minimize any third-party involvement in order to ensure future compatibility of hardware and software.

DBMS, Prime's Codasyl database management system, was selected as it would easily map the network and hierarchical structures of the pipeline inspection data. It was also capable of giving fast access to the large amount of data involved. In addition it has a query and report generator (DISCOTER) which could be used for *ad hoc* enquiries.

In general the Prime PT200 terminals are used for standard editing and reporting. However the system also includes a number of graphical reports and analyses which are displayed online using the Tektronix 4107 terminal.

The FORMS screen handler is used to give a consistent and effective interface to the user. A third-party GKS graphics package was also selected (the graphical kernel system meets ISO and ANSI standards).

A Pragma 4160 high-resolution dot-matrix printer was selected to produce hard copy output of the graphical reports and analyses. It is capable of producing large continuous plots and is a very economical alternative to large pen plotters. The system was developed using FORTRAN 77 as the programming language and the Prime is run under its native operating system, PRIMOS.

HOW THE SYSTEM MATCHES UP TO EXPECTATIONS

CIS-PIPELINE was commissioned during August, 1986. The following few months were devoted to loading the initial database. Some of the data was entered manually, including:

- construction and environmental data;
- major results from inspection and maintenance earlier than 1983: burial condition, free spans, area inspected.

All the results since 1983 were available on floppy discs, provided by the contractors. After reformatting, these were loaded onto the system.

The system was successfully used for the 1987 inspection campaign and most of the initial expectations were met as follows:

Improvement of the awareness of the pipeline condition

Performing analyses was much easier than before, therefore these were conducted more frequently and were more accurate. As a result, the engineers gained a better knowledge of the pipelines and had more confidence in the results.

Examples of studies carried out:

- trend analysis of burial condition and free spans;
- during the summer of 1987, a major review of the *Frigg* pipelines' condition over the past ten years was performed. The result of this study is now frequently used as a reference.

Shortening of response time in finding information

The improvement in this area was very significant. In addition, there was more confidence that information can be retrieved quickly when required. Examples where this has been beneficial are:

ad hoc presentations to management and authorities;
preparing of annual reports;
answering of questionnaires from authorities such as 'Pipeline Abandonment Study Database'.

More cost-effective scope of ROV inspection

The system was used during the preparation of the 1987 ROV campaign. It was found that the scope of work was prepared in a shorter time and that it was necessary to survey fewer areas than in previous campaigns. This led to a reduction of cost. However this may not be entirely attributable to using the system.

Reduction in the number of reports

It was decided to keep the old reporting system in 1987, in parallel with CIS-PIPELINE. In the light of the good performance of the system, it should be possible to reduce the number of reports supplied by the contractors in 1988.

ADDITIONAL BENEFITS

On top of the foreseeable advantages, a number of additional benefits have arisen from using CIS-PIPELINE over the past 18 months:

- (a) Better reporting standards - Due to the establishment of a detailed format for the magnetic tapes, inspection contractors have been forced to report in a more standardized way. Consequently, the quality of reporting has improved. It is also easier to cross reference results from different inspections.
- (b) Discovery of a number of inaccuracies in earlier data - The initial database loading was accompanied by a complete re-validation of

A computerized inspection system

the data. Some inaccuracies were detected in the as-laid data (anodes position) and in earlier inspection reports (calibration of CP potential). These could have led to problems, had they remained undetected.

- (c) Lower cost of the ROV inspection in 1987 - The scope of the ROV inspection was reduced in 1987. Although this may not be due entirely to using CIS-PIPELINE, a number of areas where the lines were buried were easily identified and eliminated from the scope of work.
- (d) Preventive maintenance - In the past, only free spans exceeding the maximum allowable length were stabilized. In 1987 free spans nearing the limit were added to the scope if they were in close proximity to other free spans requiring maintenance. Using the system was of great help in identifying these areas.
- (e) Wider knowledge of the pipeline - Previously, due to the large amount of data, a limited number of people had a detailed understanding of the pipeline condition. Now, however, this knowledge is far more widespread due to the ease with which users may access the data and perform analyses.

CONCLUSION

Having been in use for the past 18 months CIS-PIPELINE has matched the initial expectations and provided a number of additional benefits.

In particular the successful use of the analysis functions, such as those providing the ability to retrieve the most recent information about each section of the pipeline, or compare results from different inspections, has greatly improved the awareness of the pipeline condition. Other major benefits include:

- improved scope of ROV inspection;
- more efficient use of the engineer's time;
- greater confidence in the ability to retrieve any information when required;
- improved reporting standards.

Pipeline Pigging Technology

The decisions taken on the technical options during the initial stages have been confirmed through the usefulness and resilience of the system. The design has proved robust and well suited to the requirements. For instance a number of additions have been easily made to the libraries by the users, enabling the system to accommodate changing requirements.

10 YEARS OF INTELLIGENT PIGGING: AN OPERATOR'S VIEW

INTRODUCTION

Total Oil Marine plc has operated, for the last decade, a gas-transportation system between the giant *Frigg* field in the Northern North Sea and the St.Fergus Gas Terminal on the NE coast of Scotland. The reserves of the field, which straddle the Norwegian/UK boundary, have been exploited by the construction of two large-diameter high-pressure gas pipelines to St.Fergus.

This paper looks at the background to the pipelines, and in particular at the decision to use internal inspection by various types of intelligent pigs as an element of internal condition monitoring devised for a gas-transportation system.

PIPELINE DETAILS (SEE FIG.1)

The two lines from the *Frigg* field to St.Fergus were constructed during 1974-1976. One line is owned by the UK Association (see *Acknowledgements* for definition of this group), and the other by the Norwegian Association (see *Acknowledgements*). Both are operated by Total Oil Marine plc. Details of the lines are as follows:

diameter	32in OD
wall thickness	0.75in
length (each)	approx. 360km
steel	API 5LX 65
maximum allowable operating pressure	149 bar

The pipelines run parallel to each other approximately 100m apart in water depths of up to 155m. Approximately half way to St.Fergus there is the

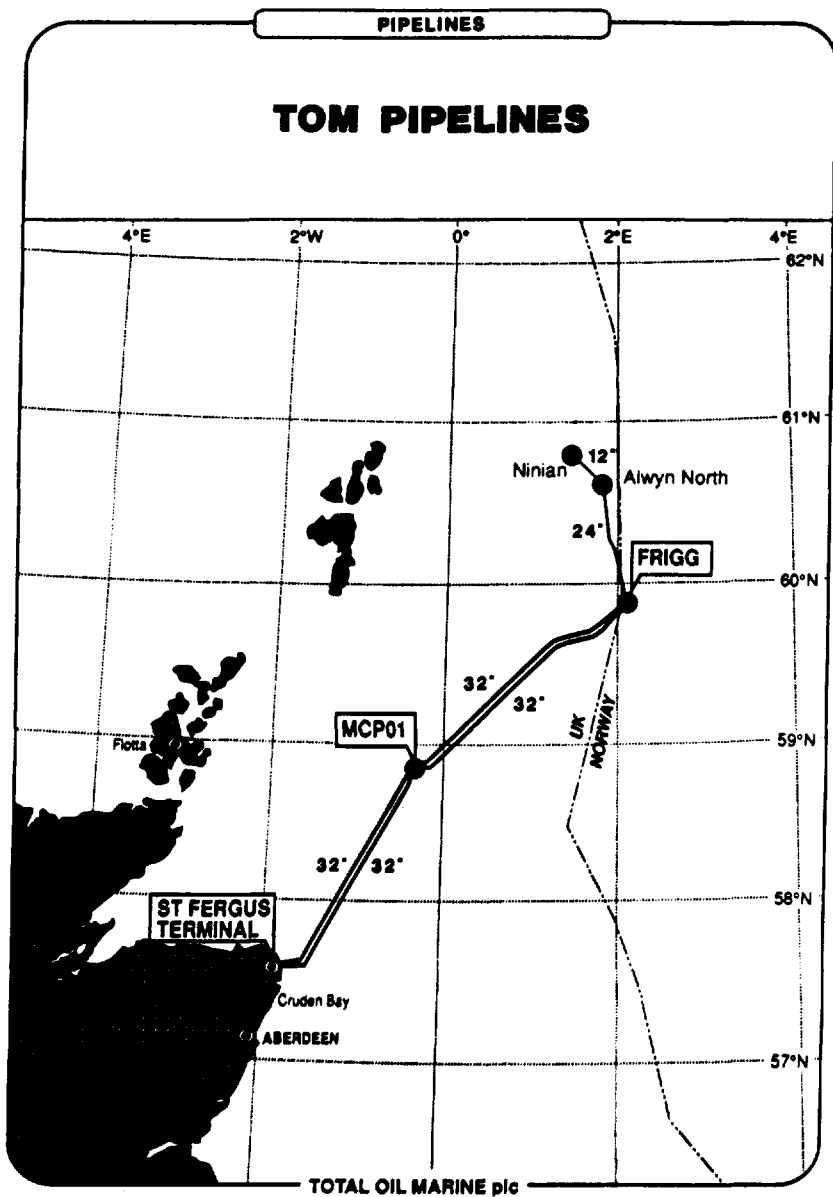


Fig.1. Total Oil Marine plc's North Sea pipelines.

manifold compression platform MCP01. In 1982 the capacity of the pipelines was further increased with the installation of compression facilities on MCP01. In addition, the platform acts as a pig launching/receiving station and allows other gas to join the system, which includes gas from the *Tartan*, *Ivanhoe* and *Rob Roy* fields.

At *Frigg* a number of other fields are linked to the gas-transportation system, namely *Odin*, *East Frigg*, *NE Frigg* and *Alwyn North*. The line to *Alwyn North* is 24in OD, and is operated by Total Oil Marine plc (ownership is the same as for the UK Association). In addition, Total Oil Marine plc operates a 12-in oil pipeline from *Alwyn North* to *Nintan Central*, as well as subsea flowlines around *Alwyn North*.

GAS QUALITY AND QUANTITY

Frigg field gas has historically made up over 90% of the gas transported to St.Fergus, and is a sweet product. The levels of H_2S and CO_2 are extremely low, and therefore the lines were fabricated for sweet service. In addition, the lines have no corrosion allowance except due to using standard API wall thickness, and any additional amount from the manufacturing process.

This is one of the reasons why a great deal of effort has been placed on internal condition monitoring.

A second reason for employing a detailed monitoring programme is the importance of the lines to the UK in general. The pipelines have recently completed the delivery of 200 Billion Sm^3 (7.02 trillion Sft^3) of gas to British Gas. The maximum flow on any one day was 80.4 MSm^3 (2.82 Billion Sft^3). More importantly, the system has, on average, annually delivered between 30-40% of all of UK gas supplies since operations commenced in 1978. Occasionally, monthly deliveries have been up to 55% of the UK gas requirements.

Internal condition monitoring of the Frigg System is based on the following methods:

- product control analysis of the gas transported;
- corrosion monitoring by means of corrosion probes and coupons; and
- internal inspection.

The first two operations are carried out on most lines, but we believe they are limited in application. Product control is not fool-proof; operational errors do occur, and in particular the most important measurement (the water dewpoint) is very problematical.

Corrosion coupons and probes are located at either end of an offshore pipeline, and will not provide information in the areas of greatest interest, i.e. downstream of a bend or at a low point in the gas line where liquid can accumulate.

We therefore believed, since start-up, that we needed to monitor the pipelines' internal condition as accurately as possible.

GEOMETRIC INSPECTION

Total Oil Marine plc has run a series of geometric pigs within the lines to prove that the lines are free from dents or restrictions which may either give cause for concern from the point of view of running a large inspection pig or because it is known that dents, if associated with gouges, etc., can substantially reduce the strength of the lines.

Geometric inspection is often used on major offshore lines prior to start-up to confirm that the lines are free from harmful restrictions. This was also performed on the Frigg Transportation System.

A T.D. Williamson geometric pig was run twice in each 32-in pipeline to produce a "signature" for the line. It was run twice to attempt to identify debris within the line which, in theory, should move from one run to the next. Accuracy of the pig was about 1% of ID (internal pipe diameter).

For the 24-in *Akwyn - Frigg* pipeline, the signature was obtained in two ways:

on the riser, by using a RIT (riser inspection tool) from H.R. Rosen;
in the pipeline, with the "out-of-roundness" pig developed by H.R. Rosen.

The order of accuracy of the vehicles were found to be 0.1mm, i.e. 0.01% ID, for the RIT and 1.0mm, i.e. 0.1% ID, for the pipeline tool.

There is now no reason to systematically run geometric pigs to either gather information about the line or to ensure the line is clear prior to running an intelligent pig. The possibility of an unknown dent occurring since the last survey can be checked by running a gauging pig. The first pig to be run has a narrow body, such as a *LBCC-2* or *Vantage IV*. This is followed by running pigs with increasing gauging plate diameters. Finally, bi-dis are run, which we have found to be the most efficient at removing both debris and liquid from the line. A typical pigging programme is detailed in Fig. 2; if the last pig and gauging plate arrive undamaged, then the inspection pig can be run with confidence.

FRIGG TRANSPORTATION SYSTEM

**Fig.2: TYPICAL PIGGING SEQUENCE
FOR INTELLIGENT PIG INSPECTION**

PIG No.	TYPE	PURPOSE
1	VANTAGE IV	GAUGING (80%)
2	BIDI	SWABBING/GAUGING (95% ID)
3	BIDI	SWABBING/GAUGING (95% ID)
4	DUMMY INSPECTION PIG	GAUGING (MULTIPLE GAUGING PLATES)
5	INSPECTION PIG	INSPECTION

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FRIGG TRANSPORTATION SYSTEM

Fig.3: GEOMETRY PIG SPECIFICATION

	GAUGING PIG	MECHANICAL	ELECTRONIC
METHOD	GAUGING PLATE	MECHANICAL SENSORS	ELECTRO-MAGNETIC FIELD
LOCATION OF DEFECT: LONGITUDINALLY	NO	YES	YES
LOCATION OF DEFECTS: CIRCUMFERENCE	YES (No. OF SECTORS RENT)	NO	YES (FOUR RADII SURVEYED)
EVALUATION OF DEFECTS	LIMITED	LIMITED TO 1% I.D.	GOOD: 0.1% I.D.
REPEATABILITY	LIMITED	LIMITED	GOOD

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**Fig.2(top). Typical pigging sequence for intelligent-pig inspection.
Fig.3 (below). Geometry pig specification.**

A summary of the different methods of checking internal geometry of pipelines is given in Fig.3.

INTELLIGENT PIGGING

Soon after start-up in 1979-80, the market of inspection pigs was investigated and tests made with the reputable pigs of the day, or 1st-generation magnetic pigs. These were "metal-loss pigs" working on the principle of magnetic-flux leakage detection. Total Oil Marine plc constructed a test line for pull-through tests; the line included a valve, barred-tee, etc., together with artificial defects in the line to evaluate the pigs' detection and sizing capacities as well as their reliability. An additional test line with a 3D bend, similar to the one installed offshore, was used, through which the pigs were pushed by water, to confirm their capabilities of passing a 3D bend.

The Linalog pig was chosen to be run in the *Frigg* lines. The first survey commenced in 1981, and a total of six runs were made, one in each half line and two further re-runs or second inspections.

During the first four runs, very little was found which required further investigation. However, minor features were reported, and these were checked following the second run. The following was concluded:

- some indications found by the first run disappeared from the second run;
- the detection accuracy was not good enough to conclude any trend.

Even with careful cleaning of the lines, such a long line (over 170km) can still have small items of debris. These produce spurious indications which cannot be distinguished from real defects or areas of metal loss.

The grading method used by 1st-generation vehicles was not sufficiently accurate to determine trends unless the trends were so marked that questions concerning the pipeline integrity would have to be asked. This was not the case for the *Frigg* pipelines. We are looking for small features which could lead to identifying trends in the pipelines' condition.

The Linalog defect grading system is given in Fig.4, but we consider it to be too wide a spread for the type of defects expected in offshore lines. Therefore in 1987, Total Oil Marine plc investigated the new pigs available on the market, namely the British Gas 2nd-generation magnetic pig and the Pipetronix ultrasonic pig.

FRIGG TRANSPORTATION SYSTEM

**FIGURE 4:
LINALOG DEFECTS GRADING**

- GRADE 1: MINOR ANOMALY
BETWEEN 15% & 30% WALL PENETRATION
- GRADE 2: MEDIUM ANOMALY
BETWEEN 30% & 50% WALL PENETRATION
- GRADE 3: MAJOR ANOMALY
MORE THAN 50% WALL PENETRATION
- GRADE U: UNCLASSIFIED ANOMALY
NOT ASSOCIATED WITH SIGNIFICANT
WALL DETERIORATION

BRITISH GAS DEFECT SPECIFICATION

PARAMETER	PERFORMANCE
<i>DEFECT TYPE</i>	
PITTING CORROSION	
(DEFECTS OF AREA LESS THAN $3c \times 3c$)	
A. MINIMUM DETECTION DEPTH	0.4c
B. SIZING ACCURACY	$\pm 0.1c$
GENERAL CORROSION	
(DEFECTS OF AREA GREATER THAN $3c \times 3c$)	
A. MINIMUM DETECTION DEPTH	0.2c
B. SIZING ACCURACY	$\pm 0.1c$
CIRCUMFERENTIAL GOUGING	
A. MINIMUM DETECTION DEPTH	0.4c
B. SIZING ACCURACY	$\pm 0.1c$
AXIAL GOUGING	
A. MINIMUM DETECTION DEPTH	0.2c
B. SIZING DEPTH	$\pm 0.1c$
<i>LOCATION OF FEATURES</i>	
AXIAL POSITION ACCURACY	$\pm 1.5m$
CIRCUMFERENTIAL POSITION ACCURACY	$\pm 5^\circ$

NOTE: c = ORIGINAL UNDAMAGED WALL THICKNESS

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Fig.4. Defect grading system.

Again, pull-through trials were performed and evaluated to decide which was to be chosen for the *Frigg* lines.

Both the pigs performed extremely well in terms of sizing accuracy and repeatability. In addition, they appear to be able to inspect near the girth weld areas. However, large practical problems were identified when running an ultrasonic pig in a major gas line; that is, the pig needs to run in a liquid batch to act as a coupling medium. The presence of any gas bubbles in the liquid could cause loss of coupling, and therefore loss of inspection results.

This problem, in terms of disruption to the production and the logistics of handling many hundreds of tonnes of liquid at either end of the line, at present is still to be solved. For example, a slug of liquid 4km long (i.e. 2km either side of the inspection vehicle) would typically be the amount of liquid required to give some confidence for a 170-km inspection run. The British Gas pig was subsequently chosen and run in the *Frigg* lines.

COMPARISON BETWEEN MAGNETICS AND ULTRASONICS

Total Oil Marine plc believes, based upon test data, that in terms of pure accuracy of defect depth, ultrasonics have a superior accuracy to magnetic pigs. This is not unrealistic when one considers the physics involved in each technique. However, magnetic pigs are more likely to pick up small, deep corrosion pits which may be missed by the individual ultrasonic pulses.

Both 2nd-generation magnetic pigs and ultrasonic pigs are capable of distinguishing between internal and external features; this is a major step forward in attempting to identify the cause, and thereby possibly save a diving campaign to investigate a feature.

The advantages and disadvantages of each type of pig are tabulated in Figs 5 and 6.

However, it appears that ultrasonic pigs are more suitable for running in liquid lines, and we therefore have chosen the Pipetronix vehicle to run in the 12-in *Ahwyn - Nintan* pipeline (15.4km long). Wax build-up on the wall of the pipeline is a problem that must be carefully addressed before running an ultrasonic pig; the wax prevents the ultrasonic pulses from reaching the pipe wall.

Another important aspect which should be considered for offshore lines is that more features occur internally, and in particular at the 6 o'clock position inside the pipe. Damage or corrosion to the external pipe wall is rare.

FRIGG TRANSPORTATION SYSTEM

Fig.5: 1st GENERATION MAGNETIC PIG

ADVANTAGES	DRAWBACKS
● CHEAP TO RUN ● NO SENSITIVITY TO FLUID ● NO SENSITIVITY TO LAMINATIONS ● LITTLE SENSITIVITY TO NON-METAL DEBRIS ● CAN BE RUN OVER LONG DISTANCES ● MODERATE LENGTH OF PIG ● MODERATE CLEANING REQUIRED ● EXTENSIVE TRACK RECORD	● INACCURATE FOR DEFECT EVALUATION ● NO SENSITIVITY NEAR WELDS ● NO SELECTION IN OR OUTSIDE DEFECT ● HIGH SENSITIVITY TO METAL DEBRIS ● LIMITED IN THICKNESS ● NO REPORT AT SITE ● NO COVERAGE IN BENDS ● CAN MISS SMALL OR SHALLOW DEFECTS ● NOT FAIL-SAFE

2nd GENERATION MAGNETIC PIG

ADVANTAGES	DRAWBACKS
● NO SENSITIVITY TO FLUID ● NO SENSITIVITY TO LAMINATIONS ● SELECTION IN OR OUTSIDE DEFECT ● SENSITIVITY NEAR WELDS ● NO SENSITIVITY TO NON-METAL DEBRIS ● MODERATE LENGTH OF PIG ● CAN BE RUN OVER LONG DISTANCES ● ACCURATE FOR DEFECT EVALUATION ● COVERAGE IN BENDS ● MODERATE CLEANING REQUIRED ● GOOD TRACK RECORD ● GOOD REPORTING	● EXPENSIVE TO RUN ● LIMITED IN THICKNESS ● LIMITED SENSITIVITY TO SHALLOW DEFECTS ● NO REPORT AT SITE ● HIGH SENSITIVITY TO METAL DEBRIS ● TEMPERATURE LIMITATION

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Fig.5. Advantages and disadvantages of magnetic pigs.

FRIGG TRANSPORTATION SYSTEM

Fig.6: ULTRASONIC PIG

ADVANTAGES	DRAWBACKS
● MODERATE COST TO RUN ● SELECTION IN OR OUTSIDE DEFECT ● VERY ACCURATE FOR DEFECT EVALUATION ● NO LIMITATION IN THICKNESS ● NO SENSITIVITY TO METAL DEBRIS ● SENSITIVITY NEAR WELDS ● REPORT AT SITE ● SENSITIVITY TO SHALLOW DEFECTS	● LIMITED TO LIQUID LINE ● SENSITIVITY TO LAMINATIONS ● CANNOT BE RUN OVER LONG DISTANCES ● NO COVERAGE IN BENDS ● SENSITIVITY TO NON-METAL DEBRIS ● LONG LENGTH OF PIG ● HIGH STANDARD OF CLEANING REQUIRED ● LIMITED TRACK RECORD ● TEMPERATURE LIMITATION ● CAN MISS SMALL DEFECTS

Fig.7: TYPICAL DOUBLE JOINT PRIOR TO SHIPMENT OFFSHORE TO LAYBARGE

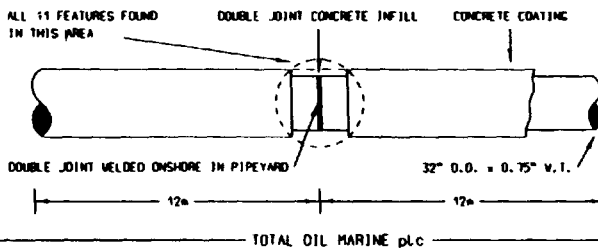


Fig.6 (top). Advantages and disadvantages of ultrasonic pigs.
Fig.7 (bottom) Typical double joint prior to shipment offshore.

Therefore, ultrasonic pigs could be more suitable offshore, as any loss of coupling is likely to be due to gas bubbles at the 12 o'clock position.

We see this is one of the advantages of ultrasonics over magnetics for offshore lines. We are looking for corrosion-type problems, and therefore the accuracy of survey from one year to another is important.

However, given the above, we consider at present the practical and logistical problems of running an ultrasonic pig in a major gas line are unresolved.

The second-generation magnetic pig appears not to be as accurate when defining defects, depths, etc., although it is stressed that this is a high-quality vehicle which can certainly reliably detect metal loss features at depths well below where failure of the line could occur.

1988 INSPECTION OF LINE 1 SOUTH

The British Gas inspection vehicle was run in the *Frigg* line 1 from MCP01 to St.Fergus during September, 1988. No disruption occurred to normal production, with a flowrate of 8×10^6 SCM/day and a speed of 2m/s. The 175-km long pipeline was inspected in one pass.

Results

Four external features above the British Gas reporting threshold (see Fig.4) were reported on the line. In addition, British Gas was requested to investigate the next seven severe features. All 11 features were found to have a common link, namely that they were within approximately 400mm of a circumferential girth weld and external to the pipe wall. This indicated that perhaps some kind of handling damage occurred during pipeline fabrication and construction. Further investigations were made into the pipe history archives to identify any other common cause or links. If this could be established, it could be unnecessary to undertake any diving work for further investigations.

Two major problems exist with diving work for investigating a feature - these are:

- the possibility of further damaging the line cannot be ignored; and
- the cost is probably 100 times more expensive than investigation of an onshore line, typically £0.5 million to investigate one or two features offshore in the Northern North Sea.

Another common link between all the 11 features was their shape and size. All were relatively local features with typically an axial length of 20-30mm, a circumferential length of 30-70mm with the depth varying up to a maximum of 48% of wall thickness.

INVESTIGATIONS

Detailed study of the pipeline history archives resulted in a common fabrication aspect for all the 11 features. The pipeline was originally fabricated in 12-m lengths and then joined or double-jointed to make 24-m lengths

prior to shipping offshore to the laybarge. This reduced the amount of welding on the laybarge, and therefore increased the laying rate. After the welding was completed onshore to form this double joint, a layer of bitumen was applied for corrosion protection, followed by reinforced concrete infill - see Fig.7. At the start of pipelaying, where the concrete thickness was 4.875in, it was found that the concrete infill was cracking and spalling due to lack of reinforcement. The double joints were therefore returned to shore, and the concrete infill cut off and replaced with stronger reinforcement. All 11 features that were reported by the British Gas vehicle proved to be within these double-jointed areas. Therefore, we could confidently link all features to a common construction process, and conclude that the features were caused by the cutting off of the field joint prior to replacement.

It is comforting to conclude that the 11 features reported by British Gas could independently be traced back through the pipeline history to a common fabrication process.

In parallel to investigating the cause of the features, a fitness-for-purpose assessment was performed. This assessment included:

- a determination of the significance of the features with respect to current pipeline operating conditions; and
- a consideration of the fatigue life of the features. The actual tensile and toughness properties of each pipe joint was used in the calculations.

As all 11 features were located in the line pipe itself and not associated with girth welds, plastic collapse analysis was used in determining their significance.

All the 11 features proved to be insignificant with respect to current operating conditions, and analysis has indicated that all the features would have survived the stresses imposed during pipelaying, hydrotest and maximum operating conditions. Fatigue-life calculations have shown that the features have a lifespan of over 60 years (the longest time calculated).

CONCLUSIONS

Total Oil Marine believes that the use of intelligent inspection vehicles is a necessary item within the overall inspection programme of a major pipeline system. The quality of the equipment now available is able to give the pipeline engineer reliable information with respect to:

10 years of intelligent pigging

the detection and sizing of features;
distinguishing between internal and external features;
inspection close to weld areas.

In addition, Total Oil Marine believes in carrying out baseline inspections on all new major pipelines.

The type of intelligent vehicle chosen depends upon the type of features or defects which are of particular interest, as well as the logistics of running such a vehicle. Ultrasonics may have a role in offshore lines where particular interest is focused on internal corrosion at the 6 o'clock position. Good cleaning programmes must be incorporated as part of the overall inspection programme to remove as much debris as possible. This is especially true for removing wax from oil pipelines.

Total Oil Marine would also like to stress that good record-keeping with respect to pipeline history is vital in aiding the pipeline engineer to investigate fully the importance of any defects or features located during an intelligent pigging programme.

ACKNOWLEDGEMENTS

We wish to thank the owners of the Frigg Transportation System, i.e.:

Norwegian Association	Elf Aquitaine Norge AS
	Den Norske Stats Oljeselskap AS
	Norsk Hydro AS
	Total Marine Norsk AS

UK Association	Elf UK plc
	Total Oil Marine plc

for the authorization to present the above information.

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THE ZEEPIPE CHALLENGE: PIGGING 810km OF SUBSEA GAS PIPELINE IN THE NORTH SEA

INTRODUCTION

The Zeepipe Transportation System is being developed to deliver sales gas from the *Sleipner* field and later from the *Troll* field in the northern part of the North Sea to continental Europe. Delivery points will be Zeebrugge in Belgium and Emden in Germany. The deliveries to Emden will be through the Statpipe/Norpipe system (see Fig.1). Fully-developed, Zeepipe will comprise about 1300km of pipelines and will, together with Statpipe/Norpipe, form the backbone of Norwegian gas transport to the Continent. The gas transport capacity of these systems will be significant; in terms of energy equivalent, it will be three to four times Norway's present electric power consumption.

Phase 1 of Zeepipe will be operational by 1st October, 1993, and consists of a 40-km, 30-in pipeline connecting *Sleipner* to the Statpipe system, and a 810-km, 40-in pipeline between *Sleipner* and Zeebrugge. An onshore receiving terminal for control and metering purposes will be located in Zeebrugge. The Phase 1 daily transport capacity will be 39MMSCM (million standard cubic meters). Relevant parts of the project schedule are shown in Fig.2.

Phase 2 will be operational 3 to 8 years later, and will connect the *Troll* field to the *Sleipner* platform and to the Statpipe/Norpipe system, respectively.

Phase 3 is defined as installation of additional compressor facilities in the system, including a possible future compressor platform approximately midway between *Sleipner* and Zeebrugge. The timing of this phase is dependent on further gas sales. The ultimate daily transport capacity will be 62MMSCM.

The 40-in diameter, 810-km pipeline from *Sleipner* to Zeebrugge will be the longest and largest subsea pipeline ever built. The pipeline was originally designed with a platform at the mid-point for tie-in of a future compressor platform and to enable the line to be pigged in two sections. Recent advances

Pipeline Pigging Technology

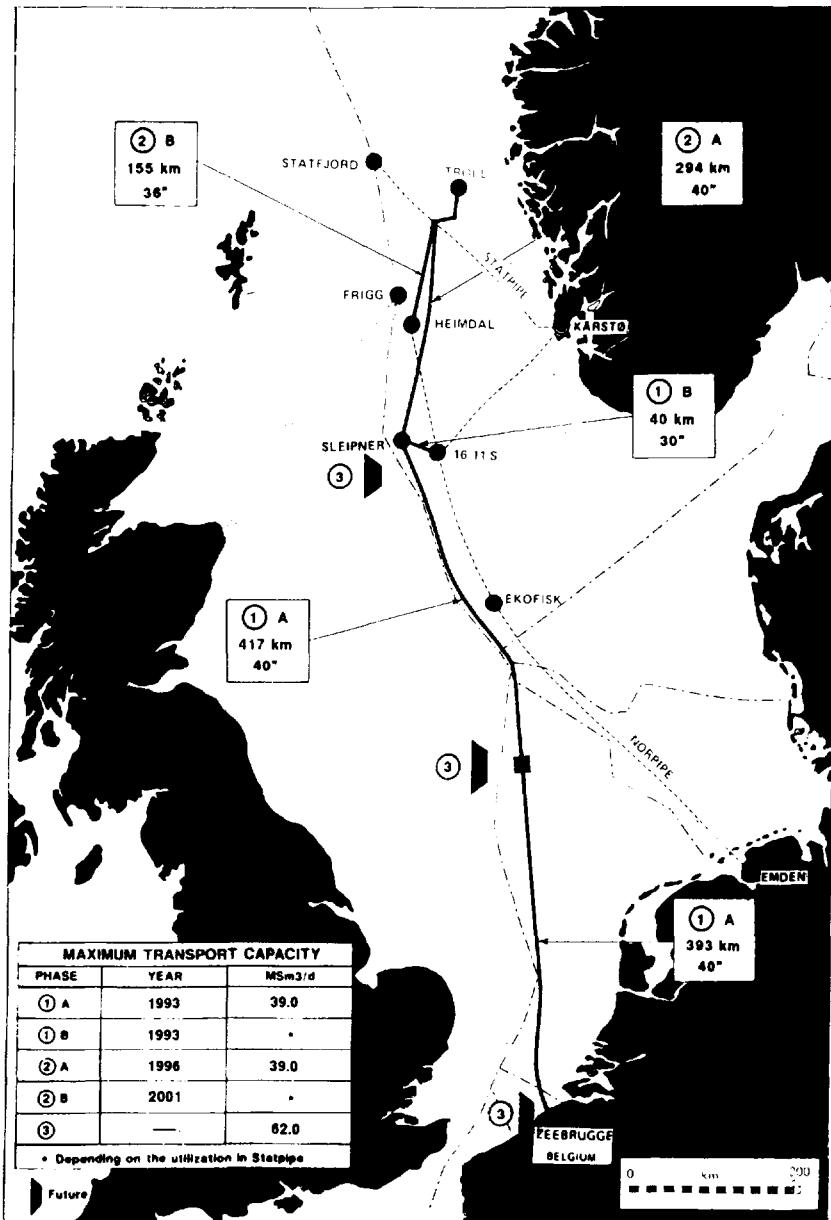


Fig.1. The Zeepipe system.

The Zeepipe challenge

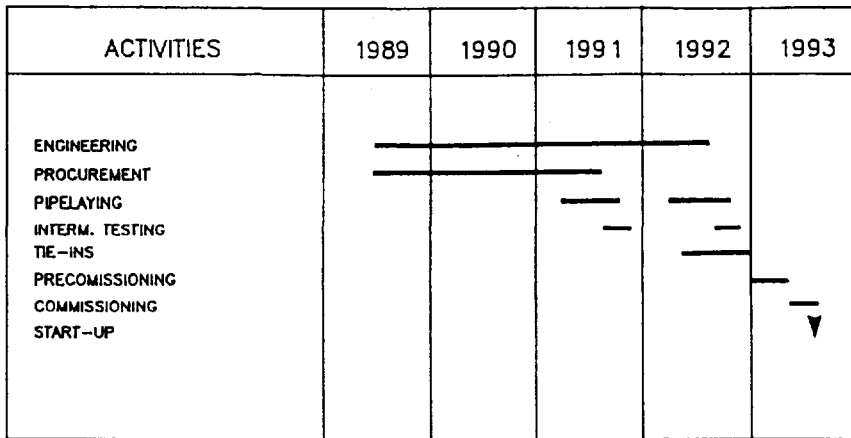


Fig.2. Zeepipe construction schedule.

in intelligent pigging technology have made it possible to inspect the total 810-km gas pipeline as one pigging section. This makes it possible to eliminate the intermediate platform and make substantial savings, based on the conclusion that conventional pigs will be capable of running this length during the precommissioning and commissioning operations. Conventional pigging is not envisaged during normal operations.

By adopting the long-distance pigging concept, the precommissioning and commissioning operations will be simplified. The number of offshore operations will be reduced, and the need for special vessels and *flotels* is eliminated. Most of the precommissioning and commissioning pigging operations will now be performed from on-shore.

The tie-in of the future compressor platform will be performed using more cost-effective alternatives, e.g. a subsea valve station or cold/hot tapping techniques. This paper describes the long-distance pigging of the Zeepipe system.

PIGGING IN ZEEPIPE

Definitions

Although most people will be familiar with the terminology used in this paper, there are some words and phrases which are sometimes used in

different contexts. The following definitions are included to avoid misunderstandings:

Intermediate testing: Flooding, precleaning, gauging and hydrostatic pressure testing performed on separate pipeline sections after completion of the laying operation/laying season.

Precommissioning: Consists of welding-sphere removal, cleaning and system pressure testing.

Commissioning: Consists of dewatering, drying and pressurization.

Pigging operations

The Zeepipe challenge - pigging of the world's longest subsea gas pipeline - will represent a further development within pigging technology; it is almost twice as long as the present largest single-section offshore gas pipeline.

The long-distance pigging concept was evaluated and decided upon during the conceptual phase. Several studies were performed and most of the relevant operators and pig manufacturers were consulted. Some of the manufacturers claimed that their present standard pigs would be capable of running this distance. Most of them, however, believed that some development or design work would be necessary.

The main characteristic of the Zeepipe system is the pipeline length, and consequently the large schedule impact from any requirement for repeated pigging operations. It is less effective and requires more resources to perform effective cleaning of longer pipelines. A precleaning operation is therefore included in the intermediate testing operation which is performed on shorter sections prior to tie-in. Furthermore, cleanliness during laying operations is of paramount importance.

Pigging during the project phase will consist of flooding, gauging and precleaning during intermediate testing and welding-sphere removal, cleaning and dewatering during precommissioning and commissioning.

During normal operations, only inspection pigging, including necessary pre-pigging to prove the pipeline every fourth to sixth year, is foreseen.

Pigging conditions

The main area of concern related to pigging length is wear, i.e. wear down of the discs and cups in contact with the pipe wall.

The Zeepipe challenge

Except for the length, the Zeepipe design does not contain any features which will reduce the pigging performance compared to present normal practice. Rather on the contrary, the system has been designed with careful attention to pigging, including the following:

- internal coating to reduce pipe wall roughness;
- constant internal diameter;
- full-bore valves and tees;
- minimum 5D radius bends;
- separate pipe-cleaning procedures during fabrication and coating;
- separate procedures and follow-up during pipelaying to avoid internal debris; and
- pipeline precleaning during intermediate testing.

The precautions related to pipeline cleanliness are partly based on earlier experience, where extensive operational cleaning had to take place after start-up to remove ferrous debris.

By keeping the pipes clean during fabrication and coating, and by maintaining the cleanliness throughout the construction phase, simplified and less time-consuming precommissioning and commissioning operations can be achieved and operational cleaning can be avoided.

Pigging facilities

Pipeline: The pipeline will be of a constant 966.4mm inside diameter and have a thin-film epoxy coating with a thickness of between 40 and 60 microns.

The pipes will be of 12.2m nominal length with approximately 100mm at each end of the pipe uncoated. Thus, of the total length of 810km, approximately 13km can be assumed to be "bare" pipe. Weld penetration is limited to 3mm maximum, and out-of-roundness is controlled to 1.5% maximum. All bends are 5 diameters radius. All tees greater than 40% of the main line diameter will be barred.

Profile: The water depth at *Sletpner* is 80m. The longitudinal profile of the pipeline between *Sletpner* and Zeebrugge is smooth and gradually rises towards Zeebrugge.

Pig traps: The pig traps at both Zeebrugge and *Sletpner* will be bi-directional or universal. Overall length between closure flange and mainline block valve is approximately 9m.

Running conditions

Export gas will be treated to sales and transportation specifications at *Sleipner* and *Troll*, and it is not planned to carry out any conventional operational pigging. All conventional pigging will therefore be limited to the precommissioning and commissioning phases. All water used for flooding and pigging will be filtered, and strict control will be applied to prevent the ingress of foreign matter.

Medtum: This will vary depending on the type and purpose of the operation. The dewatering train is composed of slugs of methanol and diesel/water-based gels, propelled by gas. All other pigging will be with water which is filtered to 50micron (maximum).

Speed: Pig speed during the precommissioning and commissioning phases will be 0.6-0.8m/sec (2.0-2.6ft/sec). This will give a run time of between 16 and 12 days, respectively.

Pressure: The line pressure during pigging will be 25-30bar (360-435psi) maximum. This will fall to approximately 4bar (58psi) at *Sleipner*.

Temperature: The temperature during pigging will be equal to the ambient, i.e. 5°-7°C (41°-45°F).

PIG WEAR AND TEAR

Mechanical pigs

A mechanical pig is designed to have firm contact with the pipe wall. Fig.3 shows the build-up of a typical precommissioning or commissioning pig with polyurethane discs on a steel body. The guide discs normally have a diameter slightly less than the internal pipeline diameter, while the seal discs are oversized. Firm contact with the pipe wall implies wear. Dependent upon several factors, such as pipeline length, pipeline roughness, amount of debris, force between the disc and the pipe wall, propelling medium, etc., the seal discs may wear down to less than the pipeline internal diameter, thereby causing by-pass.

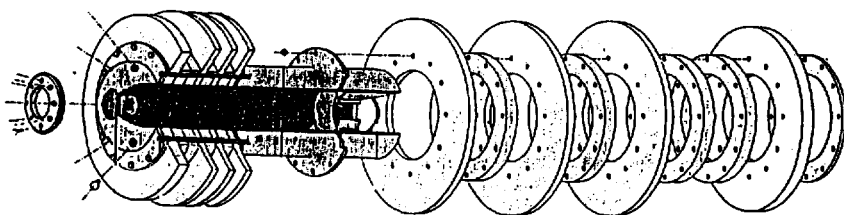


Fig.3. Pre-commissioning/commissioning pig.

If the discs for some reason are exposed to strong forces or vibration, tear may occur and in extreme cases the steel flanges on the pigs may come into direct contact with the pipe wall. The main concern related to wear is loss of sealing capability. If by-pass occurs, the driving force will be reduced, causing the pig velocity to slow down compared to the fluid velocity. However, even large by-passing should not prevent the pig from travelling at a reduced velocity. As an example, purpose-made pigs are reported to be fabricated with up to 25% by-pass ports.

Experience from other pipelines confirms that even pigs having metal contact with the pipe wall can pass through a pipeline without major difficulties. A worn cleaning pig will therefore be propelled through the pipeline, i.e. it will not get stuck, as long as the pipeline is free from obstructions.

The main concern is therefore related to loss of sealing and cleaning effect, i.e. loss of working capability.

The sealing effect is most critical during the dewatering operation. This is because the amount of water left in the pipeline will depend on pig wear. In extreme cases, excessive amounts of gas may by-pass the dewatering train and accelerate the deterioration of the train, i.e. gas in the train will reduce the dewatering efficiency.

Inspection pigs

Recent advances in intelligent pigging technology have made it possible to inspect an 810-km pipeline without intermediate pigging stations. There are several examples of pigs having accumulated more than 1000km of pigging distance in gas systems without change of discs.

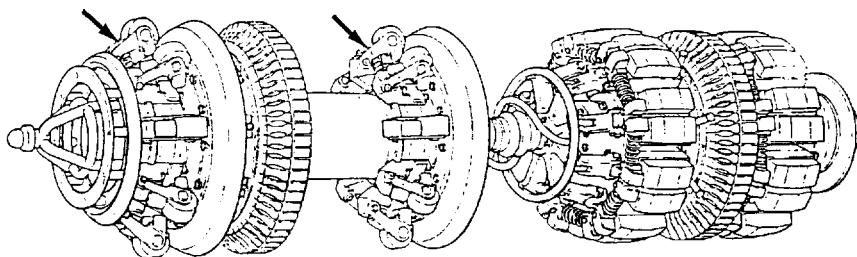


Fig.4. Inspection pig.

Wear and tear is not critical for this type of pig. They are supported by wheels, with the polyurethane cups used purely for propulsion. Furthermore, they are run through clean pipelines.

As pigs of similar proven design will be used in the Zeepipe system, this pigging operation is concluded to be well within the present state of the art. A typical inspection pig is shown in Fig.4.

Precommissioning/commissioning pigging

Welding-sphere removal

A water-pumping operation is required to remove the welding spheres used during hyperbaric tie-ins; the first long-distance pigging will take place during this operation. A mechanical pig will be included for contingency reasons should any sphere be ruptured, deflated or become stuck for any other reason. This will be the first pig exposed to any remaining debris following the intermediate testing and tie-in operations. Accumulation of debris in front of the pig will normally not prevent the pig passage. Such accumulation will, however, cause a higher differential pressure, either enabling the pig to transport the debris or to pass the debris. In some cases, the discs may flip over due to high differential pressure. This is claimed to create a jetting effect in front of the pig, causing the debris to move away. Such events may result in reduced pig velocity.

Cleaning

Cleaning is required to allow a rapid and cost-effective dewatering and drying operation and to prevent upsets during the first years of operation.

The Zeepipe challenge

An internally-coated pipeline can be expected to contain substantially less debris than an uncoated line. In addition, suitable measures will be taken to minimize the introduction of debris during construction. The cleaning requirements are therefore, at this stage, assumed to be minimal.

If, however, excessive build-up of debris occurs in front of the cleaning pigs or if the seal/guide discs wear down, the cleaning effect will be reduced. In addition to precautions taken prior to and during pipelaying, cleaning pigs are included in the intermediate testing of each section, and thereby information about pipeline cleanliness will be available prior to the final design of the precommissioning cleaning train.

The present philosophy is that cleaning will be performed using a single train of pigs equipped with magnets to remove ferrous debris. Although it is not planned, gel could be used during the cleaning operation to act as a lubricant, if this should prove to be necessary.

Dewatering

Dewatering and subsequent drying of a gas pipeline is required in order to avoid hydrate formation during the initial start-up phase and to be able to deliver sales gas according to specification.

The dewatering train will basically consist of batches of methanol. For the longer sections, a leading water-based gel and a trailing diesel-based gel have been chosen for the following reasons:

- to improve the sealing effect of the leading pigs and to prevent methanol slug depletion;
- to lubricate the pigs to avoid excessive wear of the discs; and
- to ensure proper sealing between the propelling gas and the methanol batches.

The dewatering train for the 810-km *Sleipner* to Zeebrugge pipeline will be launched from Zeebrugge, and propelled by dry gas. Propulsion speed will be between 0.6 and 0.8m/s; gas supply will be by pressure control, and the speed control of the train will be performed by the flow control system installed on the dumphine at *Sleipner*.

The use of an "incompressible" liquid (water) between the dewatering train and the flow-control station, and having the gas supply on pressure control, will ensure a smooth and stable pig travel.

At least four to five methanol batches will be included. Each of the front and rear gel batches will be split in two by a pig; this will ensure that at least one pig in each batch is fully surrounded by gel, and thereby secure the long-

distance sealing and lubricating effect. The additional pig included in the middle of each batch is judged to considerably improve performance compared with earlier common practice, where only single batches of gel were used with the pigs interfacing with the gel. The dewatering train layout is shown in Fig.5.

The main area of concern related to this long-distance pigging operation is the breakdown of the dewatering train and excessive amounts of water being left in the pipeline. If breakdown of the train should occur, two possibilities exist:

- start the drying operation taking into account the need for a longer drying period; or
- run a new dewatering train.

The dewatering train design will, however, be further improved during the engineering phase. When selecting the pigs for dewatering, experience from preceding operations will be taken into account, thereby further reducing the risk of excessive pig wear and train breakdown.

Furthermore, the pigs will be improved. For instance, by reducing the weight using lighter materials or by buoyancy tanks, or by equipping the critical pigs with wheels to support their weight, it should be possible to limit the pig wear with respect to the pipeline ID, and thereby considerably reduce any by-pass and the consequences of excessive wear.

PIG DEVELOPMENT AND TESTING

The pigs to be used during intermediate testing, precommissioning and commissioning will be purpose-made to fit the Zeepipe requirements. Pig manufacturers will be approached for development and design work, resulting in the fabrication of a prototype pig(s) which will be subjected to an extensive testing programme.

Several possibilities for reducing wear and improving sealing capability will be considered:

- Reducing the weight of the pig by employing lighter materials:* Disc wear is partly dependent on pig weight; heavier pigs also have a tendency to develop asymmetric wear. As the pig body is usually made of steel, there is a potential for improvement through weight

The Zeepipe challenge

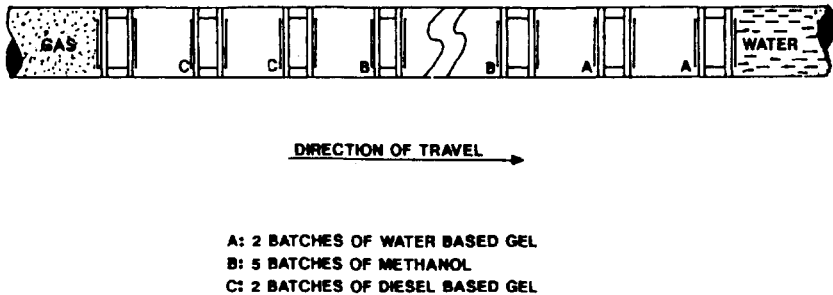


Fig.5. Dewatering train.

reduction. Lighter materials could be used (e.g. aluminium, magnesium, polyurethane, etc.) and reduced, and more symmetric, wear and extended sealing capability could be obtained.

Neutral buoyancy of the pig in water: During the precommissioning and commissioning operations most pigs are surrounded by liquid at moderate pressures. By utilizing the pig body as a pressure vessel, it may serve as a buoyancy tank, reducing the effective weight of the pig, and thereby improving the wear characteristics.

Equip the pig with wheels: Inspection pigs are normally equipped with wheels to support their weight and to create an intended rotation. The same principle has not been utilized for standard pigs, since there has been no need for it yet. However, the technique exists, and could be applied to limit the wear on sealing discs to not more than the pipeline internal diameter, independent of the distance travelled.

Balanced driving force distribution: Pigs are driven by the pressure difference across them. If the driving force is correctly distributed between the front and rear, it is assumed that smoother pig travel will be achieved, thereby reducing wear.

"Sleeping" discs: By fitting two or three discs face to face, only the "front" disc will have firm contact with the pipe wall. As it wears down, the next disc will take over the sealing. This principle has

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been used in pipelines where excessive pig wear has occurred. The possibility also exists of modifying the shape of these discs, and of prolonging the "sleeping" time.

Cups: Traditionally, pigs were equipped with sealing units shaped as cups; the use of discs is a relatively-modern technique. Cups are claimed to last longer, although discs, however, are known to perform better. A combination of discs and cups will be further evaluated.

Cup shape: Traditionally, a spherical cup shape has been used. Today, conical and parabolic cups are also available on the market. This will be further evaluated if cups are to be used.

Increase the oversize of the sealing discs: This will provide more material to wear down before sealing is lost. However, average wear may be faster. This will also be further investigated and tested.

Disc bending moment: An optimization study on disc bending moment will be performed to evaluate the distance from the pig "body" to the tip of the disc and the disc thickness and stiffness in order to obtain optimum parameters for the *Sleipner* to Zeebrugge pipeline.

Forced rotation of the pig: From the wear characteristic of mechanical pigs, it is evident that pig rotation is limited. By forcing the pig to rotate, for instance by an offset wheel, the effective length of each pig run may be improved.

Prior to selecting the pigs to be used in Zeepipe, all of the above aspects will be evaluated. Currently, the most promising concept is regarded to be the use of wheels, possibly in combination with further general improvements of the pig. When the pig design has been concluded, different opportunities for testing will be employed.

Apart from the more standard tests performed in the workshop and in test loops, these pigs, together with standard off-the-shelf pigs, will be subjected to full-scale tests in existing gas transmission systems.

The most important and relevant test, however, will be during the intermediate testing of the Zeepipe pipelines after the lay seasons 1991 and 1992, and two purpose-designed pigs are planned to be included in the intermediate testing pig train. The timing of these operations will allow further modifications to be implemented and a retest carried out, if required,

The Zeepipe challenge

prior to commencement of the precommissioning and commissioning operations.

CONCLUDING REMARKS

By adopting the long-distance pigging concept, both the precommissioning and commissioning operations have been significantly simplified. The need for a midline platform on the *Sleipner* to Zeebrugge pipeline has been eliminated, and more cost-effective alternatives are introduced for the future compressor platform tie-in. This has further reduced the maintenance requirement, and also eliminated intermediate pig handling during the operational phase.

ACKNOWLEDGEMENT

Zeepipe is organized as a joint venture with the following ownership configuration:

Company	Ownership (%)
Den norske stats oljeselskap A/S(Statoil)	70*
Norsk Hydro produksjon A/S	8
A/S Norske Shell	7
Esso Norge A/S	6
Elf Aquitaine Norge A/S	3.2985
Saga Petroleum A/S	3
Norsk Conoco A/S	1.7015
Total Marine Norsk A/S	1

**Including direct Norwegian state economic participation of 55%.*

Statoil is the operator of the Zeepipe joint venture.

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INSPECTION OF THE BP FORTIES SEA LINE USING THE BRITISH GAS ADVANCED ON-LINE INSPECTION SYSTEM

IT IS ALMOST 20 years since British Gas formulated a policy for the structural revalidation of its pipeline network using on-line inspection techniques rather than the costly and disruptive method of hydrostatic pressure testing. A research and development programme was undertaken which culminated in the production of a range of advanced on-line inspection devices based on the magnetic flux leakage technique.

These devices are now run at regular intervals through the company's 17,000km of high-pressure gas transmission pipelines, to monitor their structural integrity. Following development and production of a range of inspection vehicle sizes, British Gas now provides an inspection service to oil and gas pipeline operators world-wide.

In 1987, an agreement was reached with BP to produce an inspection system suitable for the 32-in diameter *Forties* main oil line. This required some adaptation of the basic inspection sensing systems in order to accurately locate, size and subsequently monitor a particular type of corrosion thought likely to be found in the pipeline. This paper outlines the development work carried out on the inspection system and the methods of reporting used to assist BP in monitoring the condition of the pipeline.

INTRODUCTION

High-pressure steel pipelines have become strategically placed in many countries as a means of energy transportation. Capable of handling enormous volumes of gas and oil products, they are a significant factor in most

economies, and there is a growing awareness that maintaining the integrity of such a strategic asset during its operational life has significant benefits. This realization is reinforced by considering both the financial and the environmental consequences of failures.

British Gas first formulated a policy for the condition monitoring and periodic revalidation of its 17,000km of high-pressure gas transmission pipelines in the 1970s, the corner-stone of which was to replace the traditional hydrostatic pressure test with a more quantitative and cost-effective means of assessing pipeline integrity. Detailed technical and investment appraisals confirmed that, for defined categories of pipeline defect, on-line inspection would have major performance and financial benefits over the pressure test. The investment study assumed that in the absence of a suitable commercial inspection service, it would be necessary to develop a system capable of the required performance standard. The technical study acknowledged the fact that a pressure test, whilst being a valuable aid to the commissioning of new pipelines, was both costly and disruptive as a revalidation method and further, could not fulfil the requirement for a quantitative measure of pipeline condition.

A pipeline must be designed to withstand the operational stresses associated with transportation of the product, and must also be protected as far as possible from damage and degradation during its operational life. In this latter respect, even the product, which is usually under pressure and occasionally at high temperatures, may be chemically-aggressive by its nature and because of contaminants. Thus, the pipeline may suffer damage to the internal as well as the external surface, a fact which must be accommodated by the inspection system. This requirement must also be combined with the facility for unambiguously responding to defined class(es) of defect in a potentially-aggressive product, and a pipeline environment in which the conditions are unknown in terms of debris and internal surface deposits. It is this combination of requirements which imposes the need for careful selection of the inspection technique and a highly-robust engineering solution.

British Gas undertook a detailed study of all available inspection techniques, which revealed that magnetic-flux leakage (MFL) was the preferred method for metal-loss inspection in a pipeline environment. Since that time, the technique has been the subject of major innovations and refinements by British Gas, particularly in respect of physical design, which have set it apart from other competitive systems.

British Gas began production of magnetic-flux leakage based inspection systems in the size ranges appropriate to its own pipelines, and since the late 1970s regular inspection operations have taken place in the high-pressure pipeline network to continuously monitor its condition and thus ensure its integrity.

After the introduction of the inspection systems into full operational use in British Gas, a decision was taken to offer the inspection service on a commercial basis to oil and gas pipeline operators world-wide.

BP was one of the first companies to use the inspection system, with the inspection of its 30-in crude oil pipeline between Kinneil and Dalmeny in Scotland. Following this operation, and the subsequent inspection of the 213-km, 36-in *Forties* landline between Cruden Bay and Kinneil, an agreement was reached between BP and British Gas to produce a 32-in inspection system to inspect the *Forties* submarine pipeline linking the *Forties* field with the landline at Cruden Bay in Scotland.

PIPELINE DETAILS

The 169-km long *Forties* sea line was installed in 1973/4 to carry production from BP's *Forties* field to the landfall at Cruden Bay in Scotland. This pipeline is part of the 380-km of offshore and onshore pipeline which makes up the *Forties* pipeline system (Fig.1).

When laid, it represented the biggest offshore pipeline diameter (32in) that could be used at that time, being constructed of steel grade 5LX65 with a wall thickness of 19mm. Design pressure of the pipeline was 2084 psig (142bar).

Since their discovery, the *Forties* field reserves have been increased four times from an initial 1800 million barrels of oil to a current 2470 million barrels. The field recently celebrated production of its two billionth barrel. The pipeline also now carries production from the *Buchan*, *South Brae*, *North Brae*, *Montrose* and *Balmoral* fields, as well as *Hemtdal* in the Norwegian sector. BP's *Miller* field is scheduled to produce into the line early in 1992.

Production feeding through the *Forties* system during the first three months of this year peaked to 565,000 barrels during a 24-hr period in January, 1990, and has averaged some 500,000 barrels a day, of which nearly 275,000 barrels was *Forties* field production.

Routine conventional monitoring of the pipeline system by BP had already identified the existence of some corrosion, and hence it was deemed necessary for the British Gas inspection system to accurately locate and quantify such corrosion in order to maintain the maximum operating throughput of this strategic oil line.

This routine monitoring led to the replacement in 1986/7 of part of the main sea line riser. The riser contained the internal metal-loss characteristic

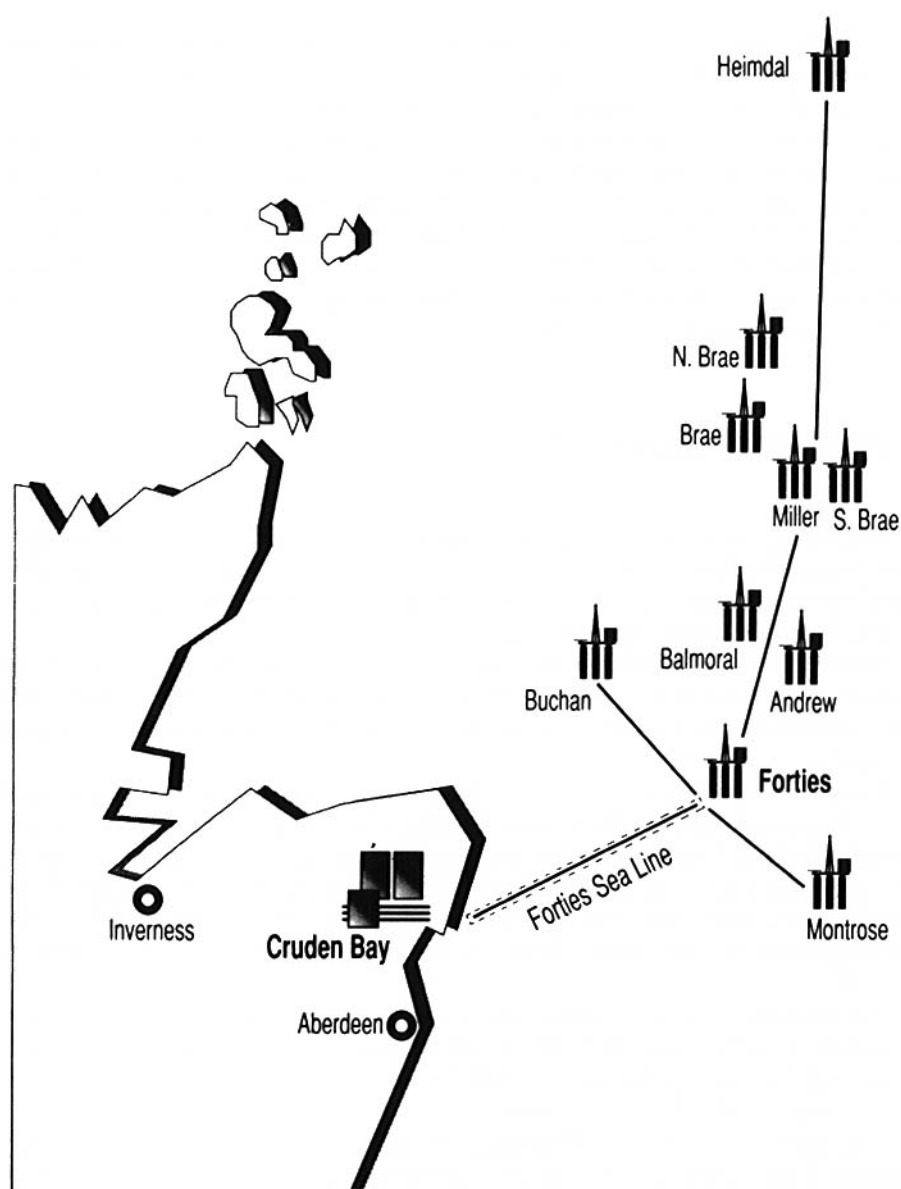


Fig.1. The Forties pipeline system.

of individual corrosion pitting, general corrosion containing pitting, selective corrosion attacks of girth welds and also areas of relatively-uniform metal loss, which in appearance would be similar to general wall thinning but with a rough internal surface texture. Fig.2 shows an example of the type of corrosion in the replaced riser.

INSPECTION VEHICLE DETAILS

The 32-in inspection vehicle produced for BP is based on the magnetic flux leakage principle, and is shown in Fig.3.

The design is based on two pressure vessel assemblies linked by a flexible coupling. The leading pressure vessel carries the strong permanent magnets onto which are bolted flexible carbon steel bristle assemblies to transfer the magnetic field to the pipe wall. The main sensing system, containing several hundred sensors, is situated between the bristle assemblies. It is designed to maintain close contact with the pipe wall even under the most difficult dynamic situations, enabling the sensors to maintain contact with the wall even at the girth weld areas, thus ensuring that all areas of the pipe are inspected.

A second sensor system is carried by the trailing pressure vessel to enable discrimination between internal and external metal loss to be obtained.

Both pressure vessel modules have the on-board signal processing units, batteries and digital recorders, required to format and store the vast quantities of information obtained during an inspection operation.

The performance specification of the inspection system was that of the standard British Gas specification, as given in Fig.4. However, the adaptations carried out to the sensing systems expanded the specification to include pipe-wall thickness assessment and sizing of specific girth weld corrosion.

These adaptations meant that all the types of corrosion damage evident on the replaced riser could be unambiguously identified and accurately sized.

INSPECTION PROGRAMME

To date three inspection operations have been performed in the *Forties* sea line, having been undertaken in June, 1988, March, 1989 and October, 1989.

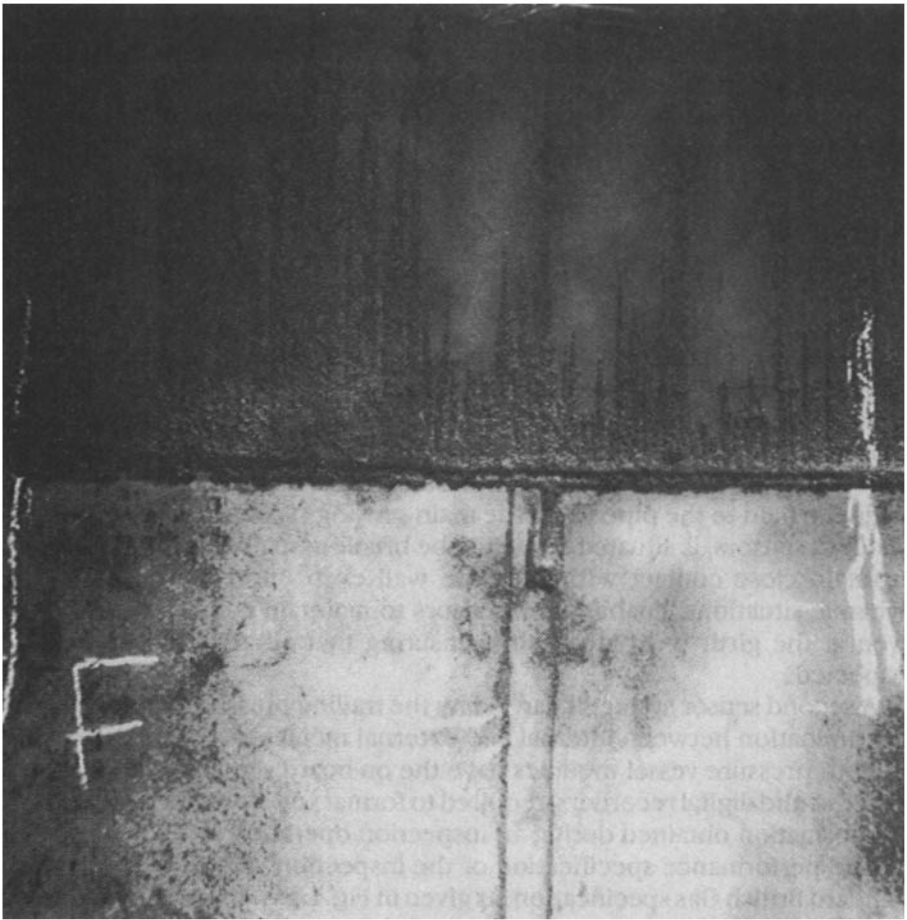


Fig.2. An example of internal corrosion.

In each of the inspection operations, British Gas supplied all the launching and receiving equipment necessary to handle the vehicles and hence perform the operations efficiently. Three types of vehicles were run by British Gas in the pipeline: a cleaning vehicle, profile vehicle and inspection vehicle.

The cleaning vehicle (Fig.5) was necessary to remove large accumulations of wax deposits from the wall of the pipe which could otherwise affect inspection data quality. This cleaning vehicle consists basically of a magnetic front module from an inspection train with sensors and electronics removed. Special drive cups are fitted to the vehicle and by-pass flows can be altered to suit line conditions.

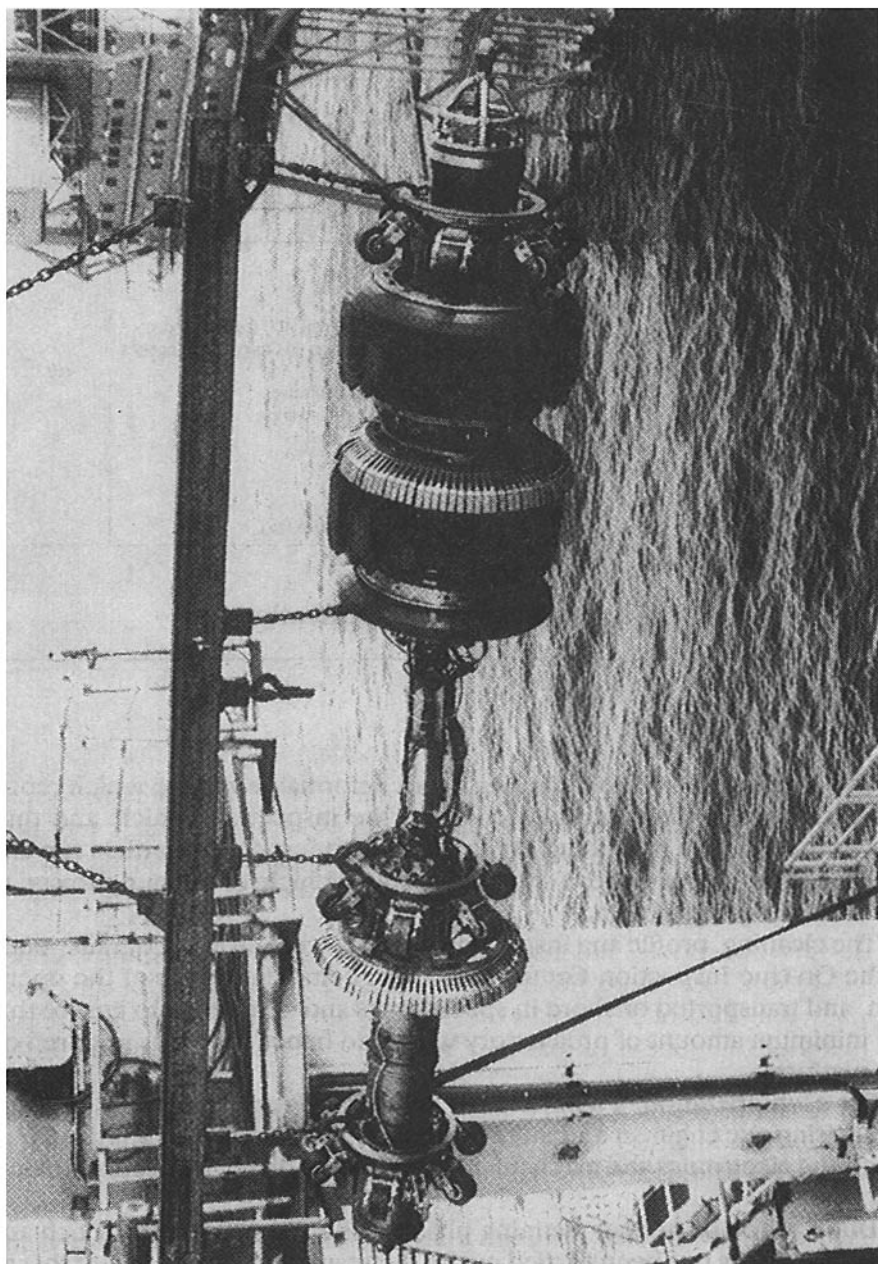


Fig.3. 32-in magnetic inspection vehicle.

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Feature	Performance required	Detection sensitivity	Sizing accuracy
Pitting corrosion	$0.4t \pm 0.1t$	$<0.4t$	$\pm 0.1t$
General corrosion	$0.2t \pm 0.1t$	$<0.2t$	$<\pm 0.1t$
Circumferential gouging	$0.4t \pm 0.1t$	$<0.4t$	$<\pm 0.1t$
Axial gouging $0.2t \pm 0.1t$	$0.2t$	$\pm 0.1t$	
Mill damage/Repair	$0.2t \pm 0.1t$	$<0.2t$	$<\pm 0.1t$
Spuria		None to be classed as significant defects	
Location		$\pm 1.5m$ irrespective of pipeline length	
Girth weld - Metal loss		Detected	
Girth weld - Misalignment		Detected	
Longitudinal weld metal loss		$<0.2t$	$<\pm 0.1t$
Metal objects near pipe		Detected when closer than 250 mm (10") (size dependent)	
Casing faults - Eccentricity		(i) Causing carrier coating damage (ii) Casing/carrier contact	
Casing faults - Carrier metal loss		$<0.2t$	$<\pm 0.1t$
CP Attachments		Ferritic attachments detected	
Bends		Detected and classified by type and angle	
Offtakes		Detected and sized	
Valves		Detected	
Ground anchors		Detected	
Pipe saddles		Detected	
Location		94% of sites within $\pm 1.5 m (\pm 5')$	

Minimum inspection requirements.

Fig.4. Performance specification.

The multi-profile vehicle run (Fig.6) is a deformable vehicle which represents the outside diameter and length of the inspection vehicle and thus proves the pipeline bore to be acceptable for an inspection vehicle run and minimizes the risk of either a stuck inspection vehicle or causing damage to the vehicle during the run.

The cleaning, profile and inspection vehicles were all fully commissioned at the On-Line Inspection Centre before the commencement of the operation, and transported offshore in special trays and containers to ensure that the minimum amount of preparatory work and hence time was required on the platform.

For each operation, a team of four British Gas personnel was deployed, comprising one engineer and three skilled technicians able to commission or repair the electronics and mechanical components on the inspection vehicle if necessary.

During the operational planning phase, a site survey of both launch and receive facilities had been carried out by the team engineer to ensure that all equipment and facilities to be provided by BP were available at the required time.

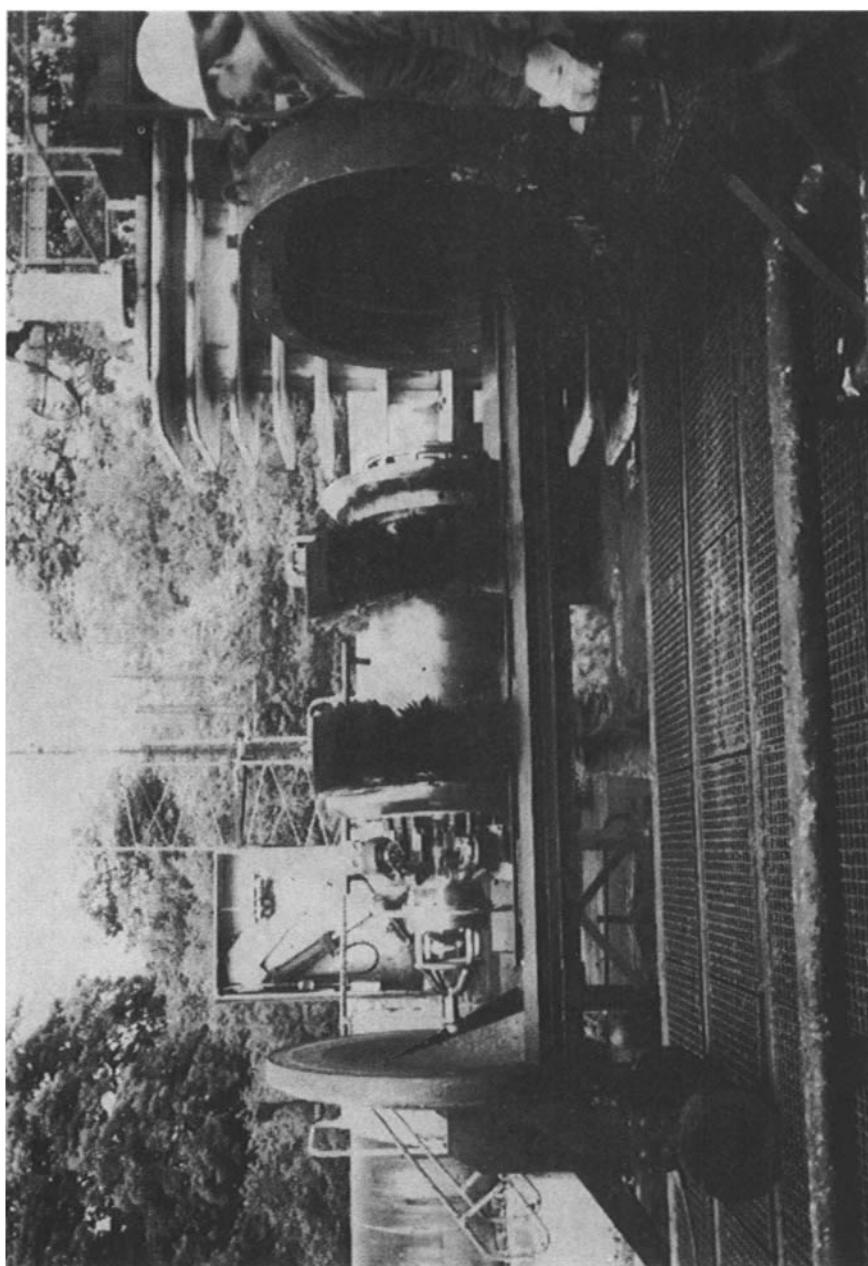


Fig.5. Cleaning vehicle.

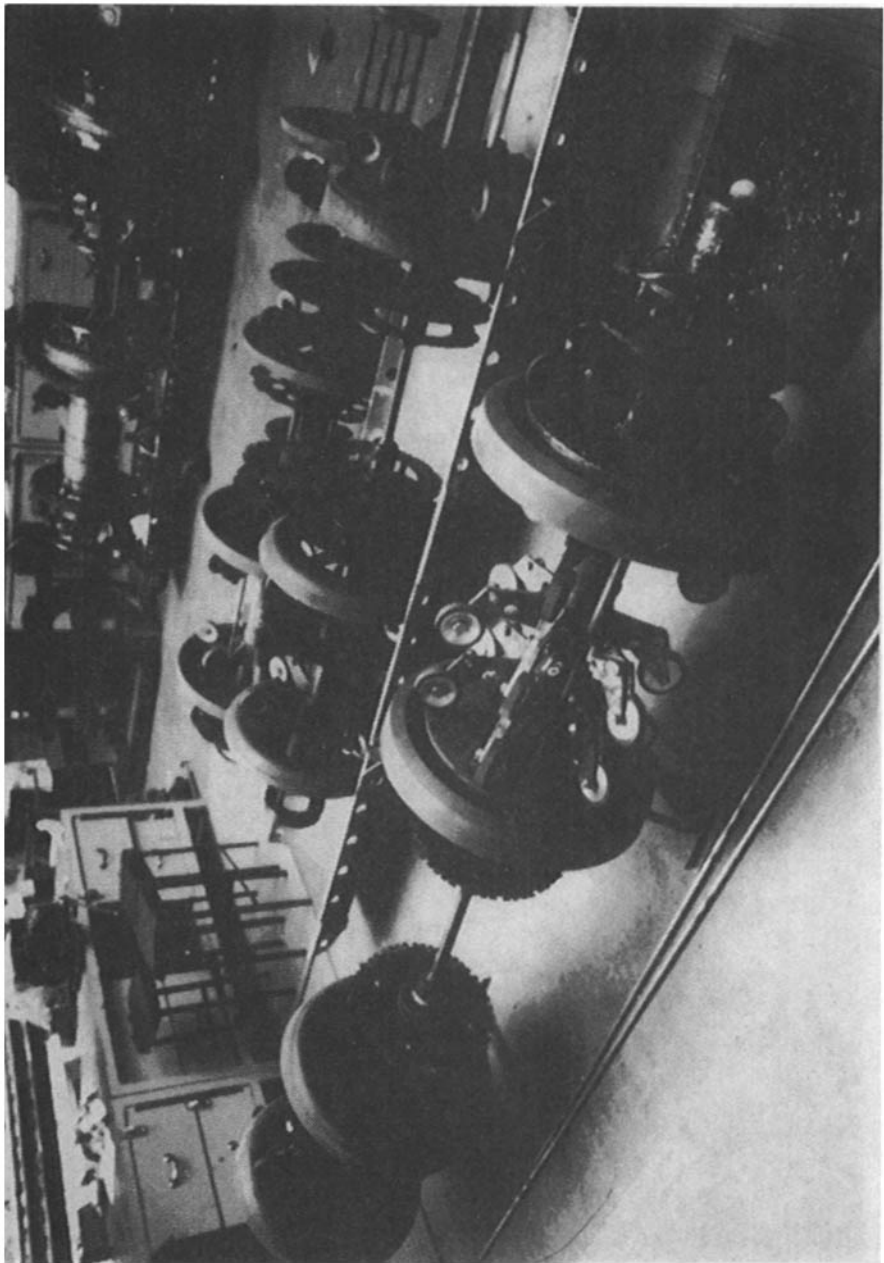


Fig.6. Profile vehicle.

INSPECTION OPERATION RESULTS

Each time the inspection vehicle was run through the pipeline, an initial assessment was carried out on the recorded data to ascertain both the quality of the data and also distance of pipeline inspected.

Full data processing was carried out at the On-Line Inspection Centre, involving transference of data from inspection tape to computer tape. All data was then fully evaluated using the extensive computing facility at the Centre.

The data produced showed that corrosion was evident in the pipeline characteristic of individual corrosion pitting, general corrosion containing pitting, large areas of pipe-wall thinning and selective attack of girth welds. The corrosion was detected from the start of the pipeline for approximately 29km, gradually reducing with distance from the launch.

It was noticed that within this area some pipe spools existed that had resisted corrosion attack even when adjacent pipe spools had shown corrosion.

From the outset, it was necessary to produce the inspection results in formats that allowed BP to:

- determine the general condition of the pipeline;
- using fracture mechanics specialists, to evaluate the effect of the condition of the line on its operating integrity;
- determine a derating curve for the pipeline validated by subsequent inspections.

As a first step, a computer listing was produced (Fig.7) giving weld numbers down the line, relative distance between each weld, and their absolute distance from launch. Values of pipe wall thickness for each spool were added to this list, but because of the very large number of readings involved in the inspection process, the values were given as:

- 1) mean value - average value for each spool;
- 2) maximum value - the maximum value obtained in the spool, this value also showing the presence of buckle arrestors;
- 3) minimum value - the value of the thinnest area of pipe in the spool; and
- 4) standard deviation - a figure which gave an indication of the variability of the wall thickness over the entire spool and hence overall condition of that spool.

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PIPELINE WALL THICKNESS STATISTICS AND GIRTH WELD CONDITION

WELD	REL. DIST (METRES)	ABS. DIST (METRES)	MEAN (mm)	S.D. (mm)	MAX (mm)	MIN (mm)	WELD CONDITION
19450	12.0	24265.7	18	0.6	19	17	★
19460	13.0	24278.7	18	0.6	19	17	★★
19470	12.7	24291.3	18	0.6	19	17	★
19480	12.7	24304.0	18	0.6	20	17	★
19490	13.0	24317.0	18	0.6	19	17	★★
19500	12.7	24329.7	18	0.6	19	17	★★
19510	12.7	24342.3	18	0.7	23	17	★
19520	12.7	24355.0	18	0.6	20	17	★★
19530	12.7	24367.7	19	0.5	20	17	★
19540	12.7	24380.3	18	0.5	19	17	★
19550	12.3	24392.7	18	0.4	19	18	★★
19560	12.7	24405.3	18	0.5	19	17	★
19570	12.3	24417.7	18	0.5	19	18	★★
19580	11.7	24429.4	18	0.5	19	17	★
19590	13.0	24442.4	18	0.5	20	18	★★
19600	12.7	24455.0	18	0.5	20	18	★★
19610	12.3	24467.4	18	0.5	19	17	★★
19620	12.7	24480.0	18	0.5	20	18	★★
19630	13.0	24493.0	18	0.5	20	17	★
19630	13.0	24493.0	18	0.5	20	17	★
19640	12.7	24505.7	18	0.4	20	18	★
19650	12.7	24518.4	18	0.4	19	18	★
19660	12.7	24531.0	18	0.5	20	18	★
19670	12.7	24543.7	19	0.4	20	18	★
19680	12.3	24556.0	18	0.4	19	18	★★

Fig.7. Pipewall thickness statistics - operation 1.

In addition to these pipe-wall thickness statistics, a general assessment of girth weld condition was given in the form of a simple grading system, which identified uncorroded welds, corrosion less than 10% depth, and corrosion greater than 10% depth.

In addition to this overall view of the pipeline condition, separate standard feature reports were prepared for the deepest individual corrosion pits found in the line. An example of this report is shown in Fig.8. For each pit the depth, width and length were given, together with location details.

From the very first inspection operation, discussion took place between BP and British Gas in an attempt to fully evaluate the vast quantity of information produced and its relevance to the operation of the pipeline. BP entered, at this time, into a separate contract with the British Gas Engineering Research Station to provide a consultancy service on the fracture mechanics' assessment of the data to determine the significance of the defects.

Inspection of the Fortles sea line

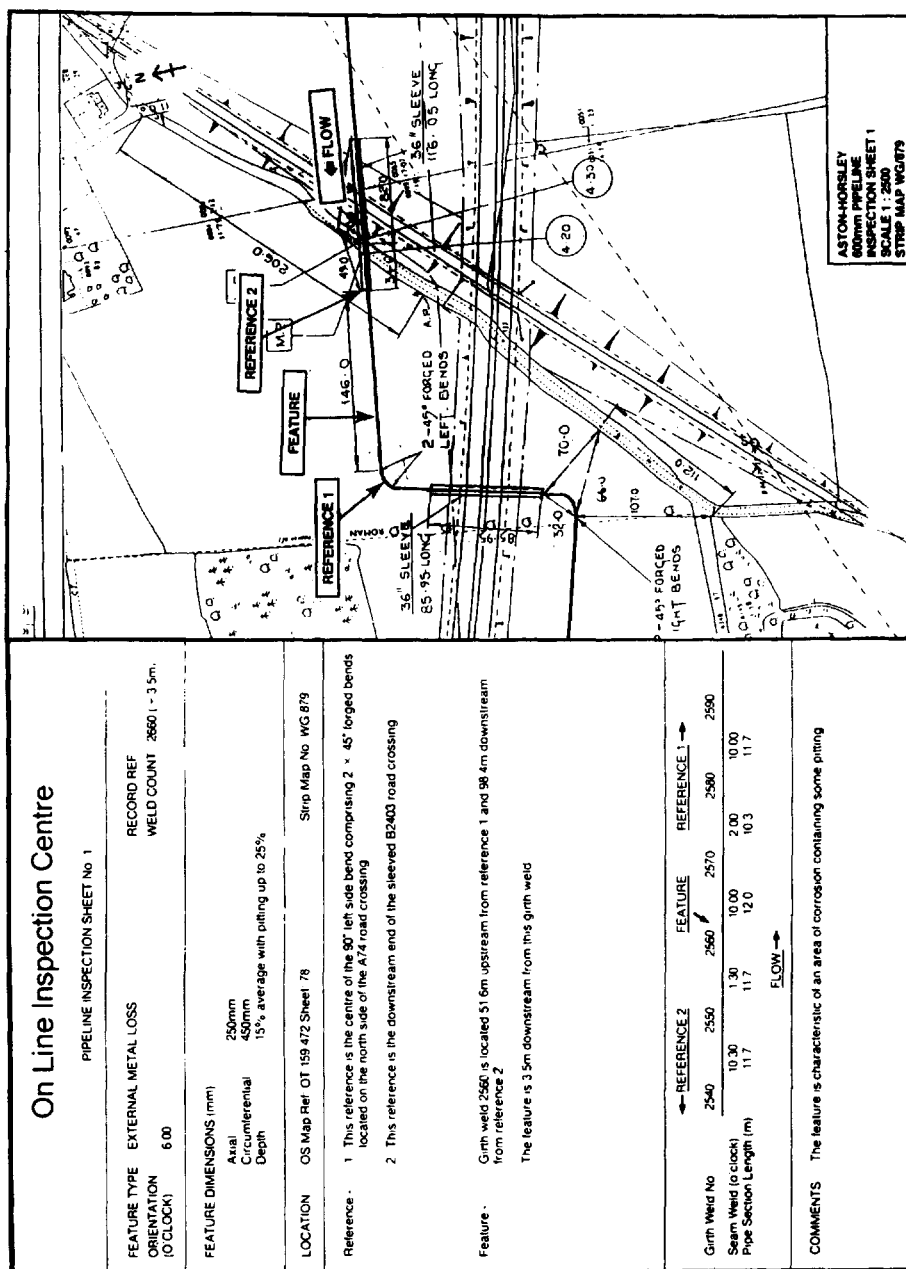


Fig.8. Standard pitting corrosion feature report.

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Report 4 Maximum Wall Thickness (mm)

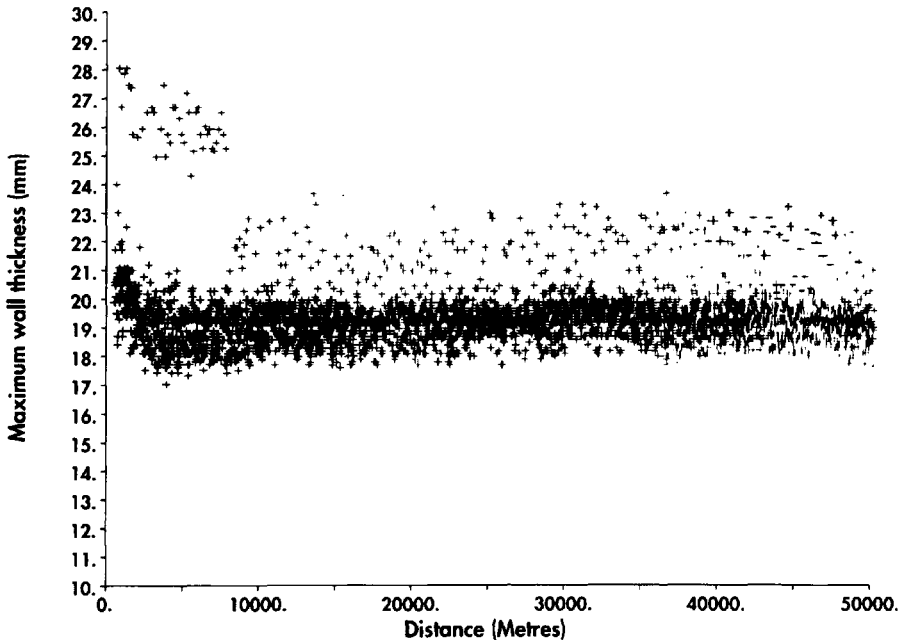


Fig.9. Pipewall thickness statistics - maximum values - operation 2.

When the inspection vehicle was run in operation 2 (March, 1989), it was important to assess the exact nature and extent of the girth weld corrosion found in operation 1, and also to determine any "corrosion growth rate".

Having an assessment of this "corrosion growth rate" would allow BP to:

- take steps to consider changing the operating conditions of the pipeline;
- to assess the long-term viability of the pipeline with respect to future perceptions of throughput;
- satisfy the appropriate regulatory authorities that all actions were being taken to operate the pipeline in a safe manner.

The results obtained in operation 2 were therefore given as before, i.e. listings of pipe-wall thickness and girth-weld corrosion severity. However, as an additional aid to viewing and understanding the results, they were

Inspection of the Forties sea line

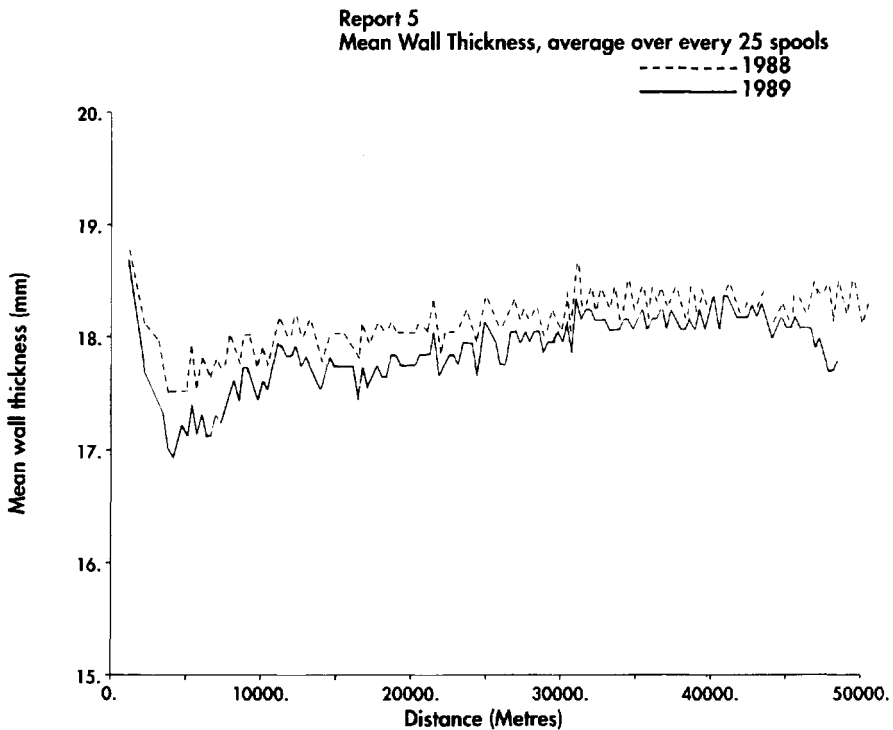


Fig.10. Pipewall thickness statistics - comparison:1988 vs 1989 results.

produced graphically. An example of this is given in Fig.9, and shows the maximum wall thickness figures plotted for the first 50km of pipeline. As can be seen from the results, the positions of anodes and buckle arrestors can be identified. A further graph was then produced (Fig.10) to compare 1988 and 1989 pipe-wall thickness data. For clarity, this graph was produced with pipe-wall thickness values averaged over 25 pipe spools. The results showed that corrosion growth had occurred.

A similar procedure was then adopted for girth-weld corrosion by producing graphs showing depth and circumferential extent. The results from operation 2 were compared with the 1988 operation results, and the graphs produced to show the increase in maximum depth of girth-weld corrosion and increase in circumferential extent. These graphs are shown in Figs 11 and 12 respectively.

As a final step, a report was produced to compare the reported sizes of individual pits from the 1988 and 1989 operation. Following presentation of

Report 3
Increase in Maximum Depth of Girth Weld Corrosion

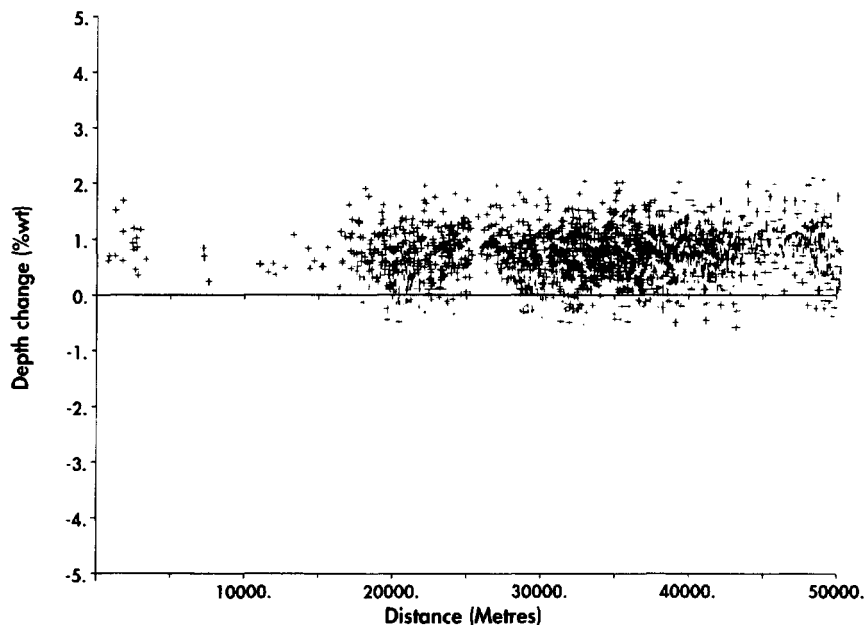


Fig.11. Girth weld corrosion - depth increase.

this second set of reports, discussions took place, with the result that BP identified particular pipe spools along the line for which they required further information. These spool plans were requested to enable BP to compare directly data produced by the British Gas inspection system against automated ultrasonic wall thickness mapping data retrieved by a diver at certain subsea locations along the pipeline. As a result, additional analysis was carried out at British Gas to produce plans of individual pipe spools giving wall thickness values along and around each selected spool. Fig.13 shows such a pipe-spool plan, with wall thicknesses given at approximately 70 positions along the spool length and at 12 positions around the circumference.

Using this type of spool-plan listing allowed BP, through the British Gas Engineering Research Station, to fully quantify the significance of the wall-thinning corrosion on the operating condition of the pipeline.

From the data obtained during operation 3 (October, 1989), reports on pipe-wall thickness and girth-weld corrosion were again produced in both graphical and listing formats. Pipe-wall thickness graphs compared this data

Inspection of the Forties sea line

Report 3

Increase in Circumferential Extent of Girth Weld Corrosion

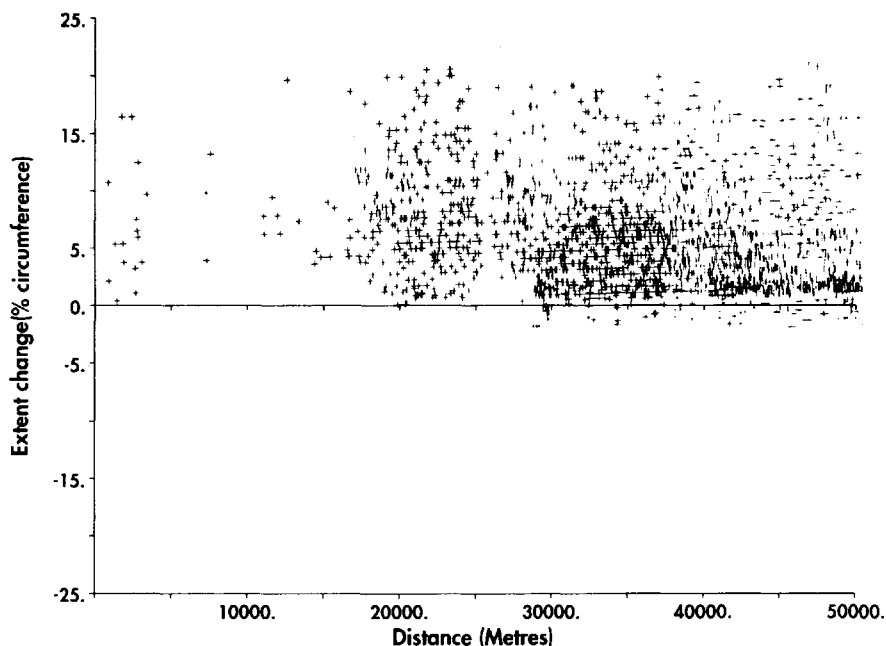


Fig.12. Girth weld corrosion - circumferential increase.

with that obtained from operations 1 and 2, similar to that produced in Fig.9. Graphs were also produced showing girth-weld depth and circumferential increase similar to those shown in Figs 10 and 11. As a final report, the deepest pitting corrosion found in the pipeline was given and then compared with those identified from the previous runs.

CONCLUSIONS

The use of the British Gas inspection system in the *Forties* sea line enabled reliable and accurate inspection results to be obtained for the pipeline, and thus ensured that decisions taken by BP on the future operation of the pipeline were taken with the maximum amount of knowledge and information being available on the condition of the line.

Pipeline Pigging Technology

Spool number : 1680

O'Clock	01	02	03	04	05	06	07	08	09	10	11	12
DISTANCE	----- Wall thickness values in mm -----											
Abs.												
1767.5	17.3	19.3	17.6	16.6	16.8	16.0	16.8	16.5	17.7	18.3	17.8	18.0
1767.7	17.3	18.6	17.8	17.0	17.0	16.9	17.6	16.8	17.5	18.1	18.1	17.8
1767.8	17.3	18.3	18.1	17.6	17.4	17.4	17.7	17.0	17.7	18.0	17.6	17.8
1768.0	16.4	18.5	17.1	17.6	16.7	17.2	17.2	17.1	17.4	17.7	17.3	17.6
1768.2	16.7	17.8	17.1	16.8	16.7	17.2	16.9	16.9	17.1	17.5	17.5	17.1
1768.3	16.6	17.8	17.0	16.8	16.2	16.6	16.8	16.5	17.1	17.4	17.3	17.0
1768.5	16.7	17.8	17.1	16.8	16.7	17.3	16.9	16.4	17.0	17.3	17.3	17.0
1768.6	16.7	17.8	17.2	17.0	17.1	16.7	17.1	16.5	17.0	17.3	17.3	17.0
1768.8	16.5	17.9	16.9	17.0	16.8	16.7	17.0	16.5	17.0	17.3	17.3	17.1
1769.0	16.6	17.7	17.1	16.9	16.2	16.4	17.0	16.5	16.9	17.2	17.1	17.0
1769.1	16.7	17.8	17.3	16.8	17.0	16.5	17.2	16.5	17.1	17.2	17.5	17.0
1769.3	16.7	17.9	17.3	17.0	17.1	16.9	17.3	16.6	17.3	17.6	17.3	17.2
1769.5	16.7	17.9	17.5	16.9	17.0	17.1	17.5	16.6	17.3	16.2	17.3	17.0
1769.6	16.8	17.8	17.3	17.0	17.0	17.0	17.3	16.8	17.3	17.8	17.5	17.2
1769.8	16.6	17.9	17.2	16.8	17.0	16.7	17.3	16.5	17.3	17.2	17.2	17.0
1770.0	16.7	17.8	17.3	17.0	16.8	16.8	17.3	16.6	17.4	17.8	17.5	17.1
1770.1	16.6	17.8	17.1	16.7	16.7	16.7	17.0	16.5	17.0	16.8	17.2	17.0
1770.3	16.5	17.8	17.1	16.9	16.7	16.4	17.1	16.5	17.1	17.7	17.3	17.0
1770.5	16.7	17.8	17.5	17.2	17.2	16.8	17.2	16.5	17.2	17.1	17.5	17.0
1770.6	16.7	17.8	17.2	17.0	16.8	16.7	17.0	16.5	16.9	17.3	17.3	17.0
1770.8	16.7	17.9	17.3	16.8	17.0	16.8	17.1	16.6	17.1	17.8	17.3	17.0
1771.0	16.7	17.8	17.2	16.9	16.7	16.8	17.2	16.5	17.3	17.5	17.2	17.0
1771.1	16.6	17.8	17.1	17.0	16.8	16.7	17.0	16.5	17.5	16.2	17.0	17.0
1771.3	16.5	17.8	17.2	16.8	16.7	16.7	17.1	16.5	17.0	17.5	17.0	16.9
1771.5	16.8	18.0	17.3	17.3	16.8	16.7	16.9	16.5	16.8	17.7	17.5	17.2

Fig.13. Pipewall thickness spool plans.

The British Gas magnetic inspection systems have encountered a wide range of sometimes difficult commercial applications, often requiring a degree of adaptation to match certain technical requirements. In the case of the *Forties* sea line, it was necessary to employ a unique sensor array in order to provide BP with specific information on the condition of the line essential to a subsequent detailed assessment of its structural integrity, thus enabling certain strategic decisions concerning its future operation to be made.

ACKNOWLEDGEMENTS

The author wishes to record his thanks to those colleagues at the On-Line Inspection Centre who have assisted him with the completion of this paper, and for both British Gas and BP for permission to publish it.

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GELLYPIG TECHNOLOGY FOR CONVERSION OF A CRUDE OIL PIPELINE TO NATURAL GAS SERVICE: A CASE HISTORY

INTRODUCTION

When pre-commissioning a natural gas pipeline, a thorough cleaning of the pipeline's internal surface is necessary to provide trouble-free gas transmission.

When the pipeline was originally in crude oil service, planned for conversion to natural gas, the cleaning becomes even more involved and critical to the pipeline's success. Pipelines generally contain various types of debris (e.g. millscale, dirt, rust, construction debris, old products, etc.), whether constructed of new pipe or converted from existing pipelines. This debris can result in an array of problems, such as frequent filter changes, reduced flow capacity, higher operating expenses, instrumentation fouling, and concern over valve seat erosion, just to name a few.

Dowell Schlumberger Inc (DS) has performed many successful cleaning operations for both operational and pre-operational pipelines, utilizing the gellypig technology developed in the early 1970s. The gellypig has been used in the North Sea, Saudi Arabia, South America, the United States, and many other regions of the world with excellent results. Pipelines have ranged from 4 to 36in diameter; from a few miles to hundreds of miles in length; and in a wide variety of services (i.e. natural gas, crude oil, products, etc.).

Dowell Schlumberger was contracted by Missouri Pipeline Co in the USA to perform gellypig services for its St. Charles project, a newly-acquired "loop" line which would be converted to natural gas service, from a previously-abandoned crude oil line.

BACKGROUND

The St. Charles Project for Missouri Pipeline Co involved converting the existing 12-in (loop) pipeline to natural gas service. The original pipeline was commissioned for transporting crude oil in 1948 and 1961, and had been abandoned since 1982. Upon abandonment, the pipeline was displaced of crude oil and purged with nitrogen. Therefore, the line was expected to be in relatively good condition.

The 12-in loop line runs from Panhandle Eastern's pipeline (PEPL) in Pike County, Missouri (near Curryville, MO), to Woodriver, IL, approximately 85 miles SE. Various sections and branches of new pipeline were included in the plans to complete the loop line, including an 11.6-mile section of 16-in pipeline between the Auburn and Chantilly stations, and 3.8 miles of new pipeline between Curryville and the PEPL tie-in (see Fig. 1).

In October, 1989, DS was contacted by Missouri Pipeline Co for recommendations to clean the existing pipeline for conversion to natural gas service. The pipeline would be cleaned, hydrotested, dewatered, dried and placed in service. The primary objectives set forth for DS were to:

1. Remove residual crude oil from the pipeline.
2. Remove loose or adhering debris which might cause operational problems in the pipeline.
3. Ultimately, clean the pipeline, such that the hydrotest water would meet EPA standards for discharge (i.e. less than or equal to: 100ppm suspended particles, and 20ppm oil and grease).
4. Provide a contingency plan to comply with the parameters in (3), in the event that the criteria were not originally satisfied.

The gellypig service was originally proposed as a single pig train, launched at W. Alton, MO, to Curryville, MO. This service would involve exchanging 12-in and 16-in mechanical pigs at the Auburn and Chantilly stations, as the pig train enters and leaves the 11.6 mile section of new 16-in pipeline.

An alternative approach was proposed and selected by Missouri Pipeline, such that the operation would be completed in two distinct phases (two gellypig trains), as follows:

- Phase 1 - from W. Alton to Chantilly Station (approximately 41.5 miles of 12-in pipeline)
- Phase 2 - from Auburn Station to Curryville Junction (approximately 24.6 miles of 12-in pipeline)

Gellypig technology for pipeline conversion

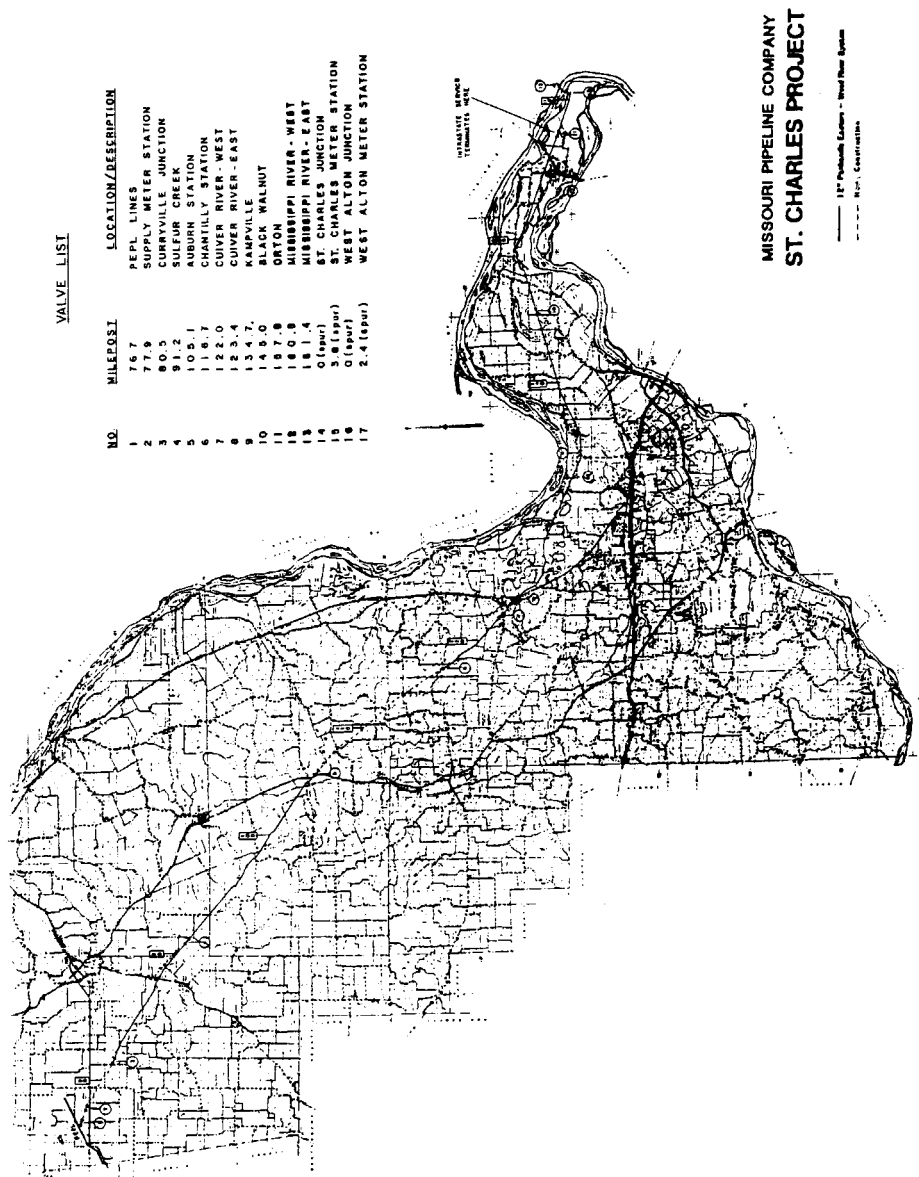


Fig.1. The St Charles project.

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TEST #	* SOLVENT	SOLVENT TESTING		Disinte- gration	% SOLUBLE
		(hr) Time	(F) TEMP.		
1	2% M002, 1% M008, 1% M009, & .2% F057	16	80	Good	100
2	2% M002, 1% M008, 1% M009, & .2% F057	8	80	Good	100
3	2% M002, 1% M008, 1% M009, & .2% F057	6	80	Good	100
4	2% M002, 1% M008, 1% M009, & .2% F057	4	80	Fair	90

Table1. Analysis of pipe samples. Note that M002, M008, M009 and F057 are DS codes. The solvent mixture is a proprietary blend of alkaline chemicals for the removal of oil, grease and other organic materials.

Conventional means of cleaning the new 16-in pipeline would be relied upon to assure its cleanliness (i.e. mechanical pigs and water from the hydrotest). This would eliminate any chance of hydrocarbons or excessive debris being carried into the new 16-in pipeline from the existing 12-in lines, since the exact composition or quantities of material along the entire length of the existing pipeline could not be confirmed, prior to the gellypig service.

The short 2.4 mile (spur) section of 12-in pipeline at the W.Alton meter station would be cleaned by the gellypig train in Phase 1, since the pig train would originate in this section. The section of pipeline from W.Alton to the east side of the Mississippi River would not be addressed at this time. A third phase (gellypig train), to clean the 11.6 miles of new 16-in pipeline, was not considered, primarily due to its feasibility.

DESIGN

In order to accomplish the objectives outlined above, a sample section of the pipe was removed and sent to the DS Industrial Division Laboratory in Houston. A complete analysis would provide the basis for the optimum job design. From the sample, the amount of debris in the pipeline could be estimated. Also, the most effective solvent for removal of the residual crude oil could be determined. From this lab. analysis, a complex gellypig cleaning train was designed.

Gellypig technology for pipeline conversion

Pipe samples were taken for analysis from the Sulfur Creek and St. Charles Junction areas. The analysis results, shown in Table 1, were used in designing the pig train. The caustic degreaser (M002, M008, M009, F057) proved to be the solvent of choice for removal of the light crude oil found in the sample pipe. Other solvent candidates included diesel-based emulsions, hydrocarbons such as kerosene, aromatics and chlorinated solvents. However, based on solubility testing, disposal concerns, economics, and safety considerations, the caustic degreaser was overall the most appropriate choice.

The amount of debris found in the sample averaged approximately 20g/ft² of internal surface area (or 0.044lb/ft²). Similar conversion projects in the midwestern US have ranged from 0.03lb/ft² to more than 0.09lb/ft²! A debris loading factor of 0.05lb/ft² was used in this case to calculate the required amount of debris removal gel. This was slightly higher than the laboratory value, which would provide some safety factor to account for loose debris localized in the pipeline, or debris loading in excess of the sampled amount.

The debris removal gellypig (GP3100) is designed to entrain up to 1lb of debris in 1gal of gel. There are many variables which can affect this number (e.g. pig train velocity, debris density, quantity of debris, mechanical pigs, and more), but for design purposes 1lb/gal is the standard number used for "debris gel strength".

The equation to calculate the amount of debris removal gel required is as follows:

$$\text{Total debris gel required} = \text{Internal surface area (ft)}^2 \times \text{Debris loading factor (lb/ft)}^2 / \text{Debris gel strength (lb/gal)}$$

The gellypig trains designed for the two phases of this service were very similar, with the only major design difference being the quantity of debris gel used, for the respective lengths of the pipeline. Based on the above calculations, approximately 36,400 and 18,200galls of debris removal gel (GP3100)

Table 2. Volume of degreaser vs contact time.

Contact Time (hrs)	VOLUME OF DEGREASER (gal) @ train velocity (ft/sec) of		
	3	2	1
8	507,168	338,112	169,056
6	380,376	253,584	126,792
4	253,584	169,056	84,528

were used for Phase 1 and Phase 2, respectively. This is enough gel to potentially entrain 36,400 and 18,200lbs of debris, respectively.

Originally, the service proposed for each phase included two trains, one for crude oil removal and one for the removal of debris. These two trains were incorporated into a single pig train; this eliminated certain components which performed the same task, reducing service time, and ultimately increasing the efficiency and feasibility of the service. The gellypig train design utilized comprised several parts (see Fig.2.).

GELLYPIG TRAIN COMPONENTS

The major components of the train and a general description of their functions are listed as follows:

1. *Separator gels* - these are a very thick, viscoelastic polymer with strong cohesive properties. The separator gels help to keep the pig train intact, acting as one large cohesive plug in the front and rear of the train. The separator gel in the front helps to prevent runaway pig trains and keep the debris gels in full contact with the pipe walls, without the rigidity of a mechanical pig, which could become stuck. In the rear, the separator gels help maintain a better seal and displace other fluids in the pipeline more efficiently.

2. *Debris gels* - these are a very sticky polymer with strong adhesive properties. The debris gels entrain loose debris into the gel slug, with a "tractor motion", as it moves down the pipeline. The debris is then suspended in the gel. Typically, a "design" value of 1gal of debris gel is used for each pound of debris in the pipeline. A mechanical (or foam) pig is mandatory behind the debris gel, for the proper dynamics to occur within the gel slug. Excessive debris "ploughed" up by the mechanical pig is carried away from the pig and entrained throughout the debris gel slug.

3. *M289/F057 degreaser* - this is a water-based caustic degreaser, comprising a mixture of four DS chemicals, including a surfactant. A volume of approximately 20,000gal of degreaser was used for each of the two phases. This was a considerably lower volume than the calculated amount from the laboratory analysis (see Table 2).

The lower volume was used to reduce costs and simplify logistics. This volume (20,000gal), would be appropriate to maintain 1 hour of contact time at 1ft/sec. The gellypig train would utilize the degreaser to "loosen" hydrocarbons dynamically, as opposed to completely dissolving them statically. The

Gellypig technology for pipeline conversion

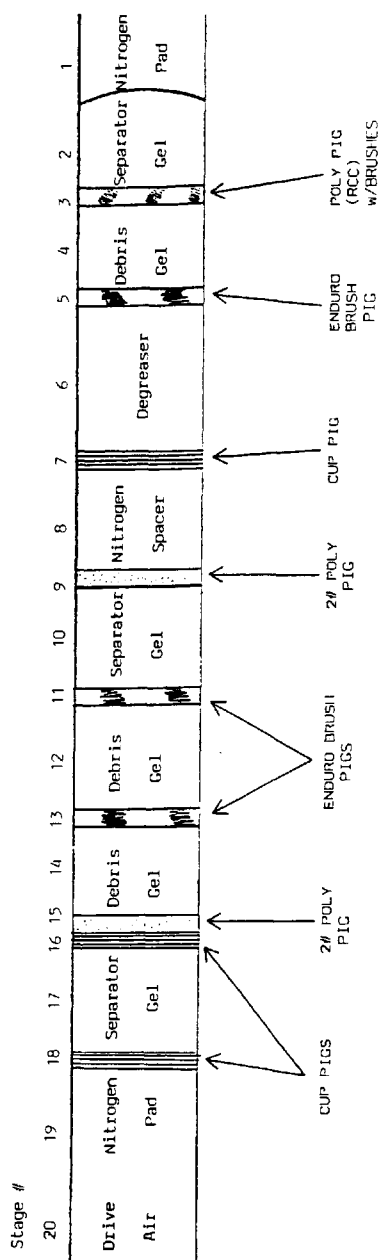


Fig.2. Gellypig train schematic.

turbulence of the degreaser, the scouring action of the brush pigs, the entrainment of the loosened material by the debris gel, the suspension of particles in the degreaser, and the use of mechanical pigs and separator gelpigs to displace material in the pipeline, all support the theory to use a lower volume of degreaser.

4. *Mechanical pigs*: Enduro brush pigs - these are very aggressive cleaning brush pigs. They comprise two doughnut-shaped brushes, which are self-adjusting as they become worn, between two cups.

Poly pig (RCC) w/brushes - these foam pigs have a durable red plastic coating in a criss-cross pattern, which contains straps of wire brushes, for light brushing. These foam brush pigs help reduce the chances of a stuck pig, but still provide a good seal and light brushing, if they do not deteriorate. The poly pig with brushes was used between the first separator and debris gel slugs, to provide some brushing action prior to the first debris gelpig, but without the high risk associated with more rigid brush pigs.

Super pig cup pig - standard four-cup *Super* pigs and unicast five-cup pigs comprised of polyurethane cups were used for efficient wiping, interfacing, displacing and sealing, in various parts of the pig train. It was used behind the degreaser, and as the final pig in the train to provide a good seal.

2# poly pig - this is a very lightweight foam pig (2lb/ft³), sometimes used as an interface between gelpigs to help prevent intermingling, or in conjunction with other mechanical pigs in an attempt to provide a better seal. These are typically options for use in gelpig trains. It is also used to absorb liquids during drying operations.

5. *Nitrogen* - was used to launch all mechanical and poly pigs, as well as a pad of nitrogen at the front and rear of the train. The nitrogen was an added safety precaution, since the trains were to be driven with air, and light hydrocarbons existed in the pipeline.

EXECUTION

The gelpig services were performed in two distinct phases, as previously discussed. Phase 1 began mixing gelpigs on 19th November, 1989. The train was launched from the W.Alton meter station on 21st November, and the pigs were received at the Chantilly Station on 22nd November. All equipment was moved from W.Alton to Auburn Station, to begin Phase 2.

Phase 2 began mixing gelpigs on 28th November. The train was launched from Auburn Station on 30th November, and the pigs were received at Curryville Junction on 2nd December.

Gellypig technology for pipeline conversion

STAGE #	DESCRIPTION	Phase I.		Phase II.	
		(ft) length	(gal) volume	(ft) length	(gal) volume
1	NITROGEN		40,000scf		40,000scf
2	60# SEPARATOR GEL	1000	6000	1000	6000
3	POLY PIG w/BRUSHES				
4	100# DEBRIS REMOVAL GEL	1000	6000	1000	6000
5	ENDURO BRUSH PIG				
6	DEGREASER	3400	20,000	3400	20,000
7	CUP PIG				
8	NITROGEN		10,000scf		10,000scf
9	2# POLY PIG				
10	60# SEPARATOR GEL	500	3000	500	3000
11	ENDURO BRUSH PIG				
12	100# DEBRIS REMOVAL GEL	3400	20,000	1000	6000
13	ENDURO BRUSH PIG				
14	100# DEBRIS REMOVAL GEL	1800	10,500	1100	6500
15	2# POLY PIG				
16	CUP PIG				
17	60# SEPARATOR GEL	500	3000	500	3000
18	CUP PIG				
19	NITROGEN		40,000scf		40,000scf
20	DRIVE AIR @ 2 ft/sec				
TRAIN TOTALS		11,600 ft.	68,500 gals.	8,500 ft.	50,500 gals.
TOTAL DEBRIS GEL launched-----		6,200'	36,500	3,100'	18,500
TOTAL SEPARATOR GEL launched-----		2,000'	12,000	2,000'	12,000
TOTAL DEGREASER launched-----		3,400'	20,000	3,400'	20,000

Fig.3. Summary of the various phases of the gellypig trains.

The mixing and launching equipment and personnel were provided by Dowell Schlumberger. A 2,400-cfm air compressor, capable of 290psig, was contracted by Missouri Pipeline. Pressure drop calculations indicated that the maximum pressure required could be as high as 516psig, to begin moving a train from a complete stop (in the worst case scenario). However, the actual maximum pressure required in the field was typically about half the calculated value. A pressure multiplier would be available, if needed, which was capable of 1,900psig and 3,000cfm. A nitrogen pumper was provided by DS, which has the capacity for flowrates and pressures well beyond the limitations of the pipeline. The nitrogen pumper was primarily for launching pigs and injecting the nitrogen pads, but could be available to increase pressure, if needed.

The gels (or *gellypigs*) and degreaser were batch-mixed in the frac. tanks, prior to injection. A quality control check was then made for gel viscosity, cross-linking of the separator gel, and alkalinity of the degreaser. The gellypigs,

mechanical pigs, and degreaser were then launched (injected) into the pipeline, in the appropriate sequence (see Fig.3).

The pig train was driven with compressed air at a target velocity of approximately 2ft/sec, which is considered to be the optimum speed for debris removal with the gellypig. On the average, gellypig trains are generally driven between 1-3ft/sec, dependent upon the parameters of the specific situation. Missouri Pipeline personnel (or its contractors), monitored the progress of the trains. The velocities of both trains were very good, with Phase 2 being relatively low, due to intentionally stopping the train at times, for various reasons. The maximum pressure required to push the gellypig trains was approximately 220-230psig, with the pressures generally ranging from 180-200psig.

When the pig train arrived at the end of each section, the mechanical pigs were retrieved, and the gellypigs and degreaser diverted into frac. tanks. The separator gel is a cross-linked polymer, which creates a very viscous three-dimensional gel. As the separator gellypig was directed towards the frac. tanks, a "breaker" was added to the gel, to "break" the cross-linked chemical bonds, thereby reducing the viscosity of the gel. Samples of the gel and degreaser were taken from the various sections of the pig train for laboratory analysis.

All gellypigs, degreaser, and material removed from the pipeline, were stored in 21,000gall holding tanks (frac. tanks), at Chantilly and Curryville. DS arranged for disposal, and assisted in characterizing the waste. Missouri Pipeline provided an EPA generator number and manifested the waste. Samples of the waste were obtained from each tank, and the waste characterized. A reputable, licensed disposal firm was then contracted to dispose of the material in accordance with any and all applicable local, state, and federal rules and regulations. The gellypigs are non-regulated, non-hazardous, biodegradable materials, and present no environmental problems in disposal. However, due to the changing composition of the gel as it passes through the pipeline, precautions must be taken to properly dispose of the used gels and materials.

The pipeline was successfully hydrotested after the gellypig service. Drying of the pipeline was accomplished by Missouri Pipeline using methanol, mechanical (cup) pigs, and many foam swab pigs.

Overall, the execution of the job went very well and according to plan, although there were some minor complications, primarily caused by the extremely cold weather. Temperatures plunged to below 0°F, and around -50°F wind chill factor, during some portions of the job. This presented some minor freezing problems when mixing the gels, storing the waste materials until they could be transported, cleaning the frac. tanks, and some mechani-

cal difficulties common to extremely cold weather. However, there were no real problems associated with the actual movement of the pig train once it was loaded into the pipeline, and no appreciable delays in the job. All frac. tanks were equipped with propane heaters to help reduce freezing problems.

RESULTS

Samples of the gels and degreaser were taken from each of the gellypig trains and analyzed for debris loading (i.e. the number of lb of debris contained in 1gal of gel). Testing was performed at the DS division laboratory in Houston.

A plot of debris loading vs cumulative train length was constructed for each gellypig train (see Figs 4 and 5). The total amount of debris removed can be estimated from the area beneath this curve. Typically, for a line to be considered relatively clean, the trend is for decreasing debris loading (to a very low value), in the final portion of debris removal gel, or a very low debris loading for the entire length of the train. Generally, values of 0.1 to 0.2lb/gal or less, in the final "slug" of debris gel, have been considered an acceptable level of cleanliness for this type of service.

The total estimate of debris removed with all gellypig trains was 28,918lb, using a total of 55,000gal of debris removal gel, 24,000gal of separator gel, and 40,000gal of degreaser. The Phase 1 and 2 gellypig trains removed approximately 20,443lb and 8475lb of material, respectively. The curves in Figs 4 and 5 both showed very good results, in that large amounts of debris were removed early in the pig train, and the amount of debris in the final portions of the debris gels were very low. The decreasing trend in Phase 2 (Fig.5) was excellent, with the debris loading values continually decreasing to an extremely low final value (0.0058lb/gal or less!). The final debris loading values in Phase 2 were not as obvious as Phase 1, since there were some increasing trends toward the end of the train, but overall the final values were very low (0.0385lb/gal or less!). The gels also exhibited a change in colour (from black to light grey), which generally indicates a decrease in suspended debris. Phase 2 gels were particularly obvious in their colour change.

The degreaser performed very well in both phases, removing more residual crude oil and debris than the laboratory analysis would have indicated, for the actual contact times and volumes used. The final hydrotest water was tested for oil and grease, and suspended particles, and was well within the limitations imposed (i.e. 20ppm and 100ppm or less, for oil and grease, and suspended particles, respectively); therefore, the final hydrotest

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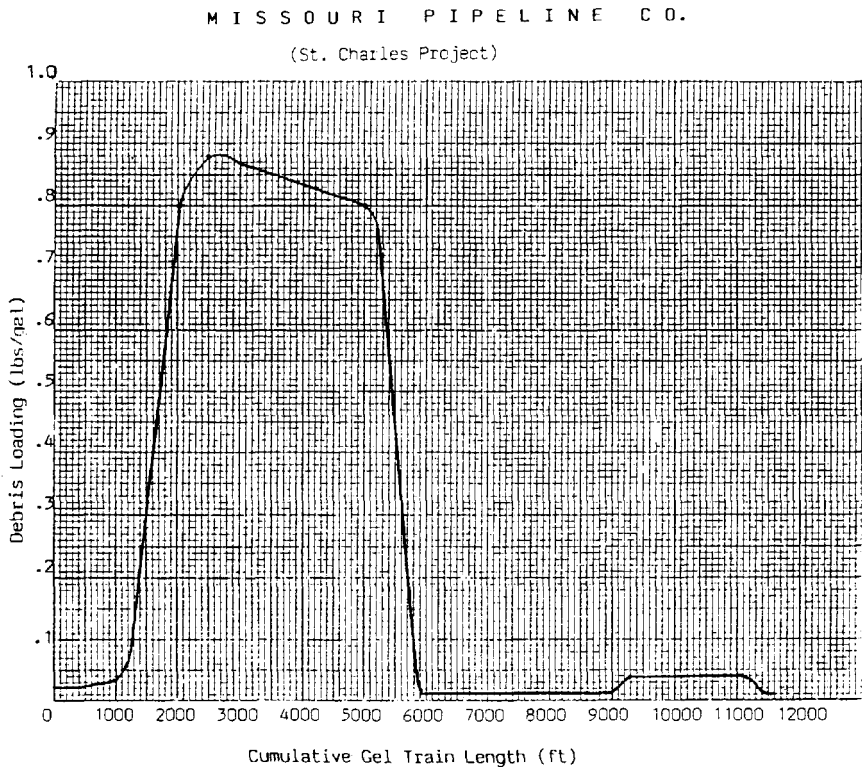


Fig.4. Plot of debris loading vs gel train length for Phase 1.

water was approved for discharge, per EPA specifications (under a permit by the Missouri Dept of Natural Resources). A contingency plan for filtering the final hydrotest water through large vessels of activated carbon, or other filtration devices, had been arranged, in case the final water did not pass the EPA criteria for discharging, but was not necessary.

A total of 119,000gal of gel and degreaser were launched in the two phases. It is estimated that approximately 117,000gal of material was received from the two gelpig trains. This resulted in a material balance of 98.4%. Residual gel, and the low amount of debris which may be present in the gel, would easily be flushed from the pipeline during the hydrotest and drying operations.

The average velocities of the pig trains in Phase 1 and Phase 2 were approximately 2.09 and 1.54ft/sec, respectively. These velocities are within

Gellypig technology for pipeline conversion

MISSOURI PIPELINE CO. '

(St. Charles Project)

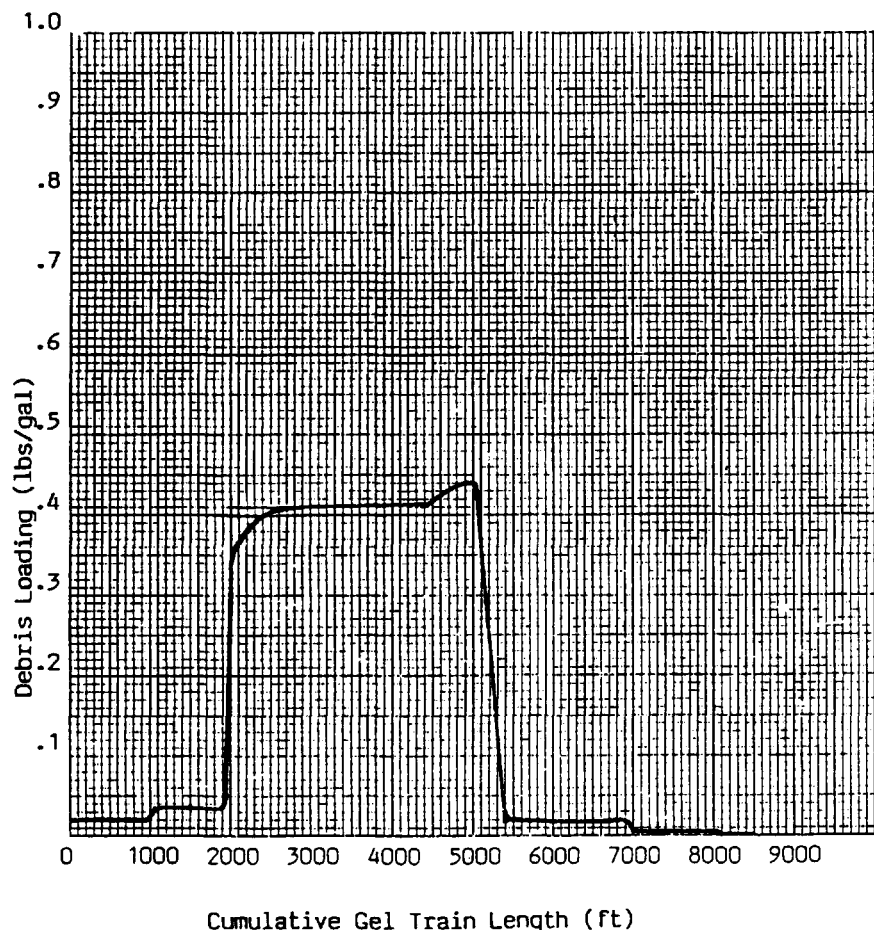


Fig.5. Plot of debris loading vs gel train length for Phase 2.

the range for optimum debris removal with gellypigs, and obviously provided the contact time necessary for the degreaser to perform adequately.

The pipeline began natural gas service on 1st January, 1990, (the scheduled start-up date). There have been no problems to report to date. There have been relatively few filter changes, with these typically occurring when the

pipeline is at or near maximum flowrate, but the debris amounts have been insignificant and easily controlled with routine filtration.

CONCLUSIONS

1. The conversion of existing or abandoned crude oil pipelines to natural gas service can be accomplished, in a manner which will reduce debris and residual crude oil in the pipeline, thereby reducing potential operational and environmental problems. Gellypigs and an appropriate degreaser are very effective in removing residual crude oil and debris in these pipelines.

2. Solvent testing under laboratory conditions may not always be indicative of the actual degree of residual crude oil removal under dynamic field conditions. There are many variables which may cause residual crude oil removal to be significantly different. In this case, the degreaser performed beyond expectations for the given contact times and volumes.

3. The removal of debris and residual crude oil can be performed by a single complex cleaning pig train.

4. The effectiveness of activated carbon or other filtration devices for satisfying EPA specifications for discharge, were inconclusive, since they were not used, although laboratory testing indicated that activated carbon would be very effective in reducing oil and grease content. Traditional methods of filtration (i.e. cartridges or bags) could adequately control suspended solids.

5. Representative sampling and efficient mechanical pigs are critical components for the total success of a gellypig pipeline service. The sample submitted for analysis appears to have been in worse condition than the average, therefore making the design conservative. The mechanical pigs appear to have performed to expectations. Both would contribute to a successful service.

6. All the following results suggest that the pipeline should be relatively free of loose debris and residual crude oil:

- (a) the final gels contained extremely low amounts of debris;
- (b) the final hydrotest water contained low amounts of oil and grease and suspended particles (i.e. approximately 5 and 40ppm, respectively);
- (c) large amounts of debris, and oil and grease, were removed in the front portion of the pig train;
- (d) the train velocities were excellent for optimum debris removal;

- (e) the pipeline has been operating since 1st January, 1990, with no significant problems.

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CORROSION INSPECTION OF THE TRANS-ALASKA PIPELINE

THE ALYESKA Pipeline Service Company operates an 800-mile pipeline which transports crude oil from Alaska's large reserves on the North Slope to the ice-free port at Valdez. The pipeline, which carries approximately 25% of the US domestic crude, was put in service in July, 1977. This paper describes the use and preliminary results of the last four years of corrosion inspection of the 48-in diameter mainline pipe by state-of-the-art, intelligent pipeline-inspection devices.

INTRODUCTION

Pipeline operators have many choices in a fast-changing pipeline-inspection industry. Technological advancements in computer, data-processing and electronic industries in the past 10 years have permitted vast leaps in advanced-pig inspection systems. Mature monitoring systems have been improved and advanced, and capabilities and systems which were not possible 10 years ago are now out of the experimental stage and are being used as commercial production systems.

Two of the primary technologies representing pipeline corrosion-inspection systems are the magnetic-flux and the ultrasonic corrosion pigs. There are many companies which provide various types of magnetic-flux corrosion pigs, and they have by far logged the majority of corrosion-pig mileage today. However, two companies in the world pig market have pioneered commercially-available corrosion pigs using ultrasound. These companies are NKK, the Japanese steel producer, and Pipetronix, a subsidiary of Preussag (previously known as IPEL-KOPP).

ALYESKA'S EXPERIENCE

During the past three years, Alyeska Pipeline has had an opportunity to use magnetic-flux and ultrasonic corrosion pigs to monitor the condition of the trans-Alaska pipeline. The company has had the resulting opportunity to compare the capabilities of the two inspection technologies using two specific pigs: the IPEL magnetic-flux pig and the NKK ultrasonic pig.

The environment for operating pigs in the Alyeska pipeline is challenging. Current throughput in the 48-in diameter pipe is 1.85million bbl/d, producing an average pig speed of 6.53mph or 9.57fps. Oil temperature varies from 125°F to 100°F. The pipe wall is 0.462- and 0.562-in thick, in grades of X-60, X-65 and X-70.

Alyeska contracted with IPEL in 1987 to run its magnetic-flux pig after a thorough review of the pig capabilities and physical characteristics. The pig was run in the summer of 1987 and the fall of 1988. The 1987 run produced a final report of 12 potential corrosion anomalies. Field excavation of each of these anomaly locations did not find any pipeline corrosion. A second run was made in 1988 with minimal hardware changes to the pig. The results of a subsequent grading analysis produced 241 possible corrosion anomalies. Field investigation in 1989 and 1990 verified corrosion in 122 of the 189 locations investigated. Because of the relatively-high success ratio in identifying metal loss, IPEL was asked to do a second grading of the data based on the results of the verifying field data. The results of the regrading produced an additional 178 possible corrosion locations. The total reportable corrosion anomalies from the 1988 pig run is 419. As of December, 1990, Alyeska has field-inspected 312 of these anomalies with the following results:

Ultrasonic corrosion pig

Alyeska has been working with the NKK Corporation since 1984 discussing the possibility of developing and testing a 48-in diameter corrosion pig using ultrasonic transducers. After years of development by NKK and several test runs in the Trans-Alaska pipeline, the NKK pig ran its maiden run in June, 1989. This run reported 419 possible corrosion anomalies. Field investigation of 280 locations of the 413 possible sites found 194 corrosion anomalies, a successful call rate of 69%. It must be noted that this first report by NKK was based upon the grading criterion that three adjacent circumferential transducers must collect data indicating metal loss before corrosion can be reported. Alyeska believes that this criterion may be improved, even though

the technique can measure pits as small as 1.75in in diameter and as shallow as 10% of the pipe wall.

Alyeska has asked NKK to institute grading a sample of the pig data based on the criterion of a single or two adjacent transducers. That is, corrosion will be reported when one or two transducers collect data which reflects metal loss greater than 10% of the pipe wall. This will provide measurement of pits as small as 0.5in in diameter.

Single- or double-transducer grading is a feasible objective, but in the early production stage of the NKK pig development this is not practical because:

1. Single- or double-transducers do not "read" the same location on the pipe wall for each pig run.
2. NKK computer-assisted grading is a very labour-intensive process.
3. The computer-assisted/manual grading process increases the potential for analysis errors.
4. The increased pipe-wall coverage capability of the single transducer is second choice to additional pig runs.
5. The Alyeska pipeline's 800-mile length is a staggering inspection assignment without a fully-computerized analysis process.

Alyeska is continuing to investigate the results of the reported corrosion anomalies from the IPEL and the NKK pigs to meet its corporate commitment of no oil leaks. Alyeska has scheduled the 1991 pig run by NKK for August.

Magnetic flux vs. ultrasonic technology

Alyeska's pig inspection programme provides a unique opportunity to compare the results of a sophisticated magnetic-flux pig and the high-tech ultrasonic corrosion pig. The differences between the two technologies are well known. The magnetic-flux technology uses sensors to determine the change in the flux field due to corrosion anomalies. The ultrasonic technology uses transducers to send high-speed sonic waves to the inner and outer pipe wall, and measures the time difference between the time of the pulses to calculate the wall thickness. The obvious difference between the two is that the magnetic flux is a detection and interpretation method, whereas the ultrasonic method is a measurement method.

The following data is based on the 1988 run of IPEL and the 1989 and 1990 NKK pig runs. We believe that this data supports the assumption that ultrasonic pigs may be more accurate due to their measurement capability.

Considerations in the decision of selection of which pig technology to use in a pipeline system are as follows:

Pipeline Pigging Technology

<i>Pig run</i>	<i>Reported</i>	<i>Total investigated</i>	<i>Field-verified corrosion</i>	<i>% verified</i>
1st report	241	189	122	65
2nd report	178	123	69	56
Total	419	312	191	

The unverifiable reported anomalies were the result of laminar inclusions, other magnetic variations and false reports.

Table 1. Magnetic-flux corrosion pig field verification results.

	<i>Magnetic flux</i>	<i>Ultrasonic</i>
verified calls where a pipe anomaly was found	93%	97%
verified calls where corrosion was found	61%	73%
verified calls that required repair	7%	29%

Table 2. Comparison of field results of pig technologies.

oil or product lines can use either type, but ultrasonic pigs are usually limited to use in liquid lines because of the need for a couplant.

ultrasonic pigs, because of their higher level of accuracy, have distinct advantages in areas where pipelines have limited accessibility, such as deep burial areas, river crossings or high-density population areas.

ultrasonic technology has the capability of measuring isolated patch or pit corrosion to depths of 10% of pipe wall, whereas at the present time magnetic flux is more suited to detection of general corrosion to depths of 20% to 30% of pipe wall in 48-in diameter pipe due to performance of sensing units and experience and capability of the personnel grading the data.

magnetic-flux pigs may not be able to detect corrosion in the area adjacent to the girth weld and longitudinal seams due to sensor lift-off. If these heat-affected zones are of specific concern, the ultrasonic pig will produce data up to the weld.

Both corrosion technologies have some blind areas: that is, areas which, because of limitations in the technology, are not able to produce valid data.

For example: the ultrasonic transducers are dependent on a reflected echo to be able to calculate the remaining wall thickness; when a sloped or curved surface is encountered, the echo is reflected away from the transducer, causing an invalid or no signal. For this reason, ultrasonic pigs have limitations or blind areas in bends, dents, and in slack line conditions, due to loss of couplant. Magnetic pigs have blind areas near girth, longitudinal, and spiral welds, at expander marks, and in tight bends.

Measurement accuracy also varies between the two technologies. As noted in the data presented in Table 2, the field verification results of the two technologies show a small advantage to the ultrasonic technology in this example. This is probably due to the subjective method of grading or interpreting the signals which results from the magnetic pig. The reported corrosion is dependent upon a technician making a judgment on whether or not a sine-type wave represents corrosion.

Pipetronix has made significant improvements in its magnetic-flux pig since running the Alyeska pipeline in 1988. The improved features are high-strength magnets, highly-sensitive and smaller-sized sensor units, and digital processing of data. In further detail, these enhancements are:

- detection capability: expected to increase metal-loss detection from 30% of pipe wall to 10%;
- sensing units: are physically reduced in size minimizing blind areas and girth weld lift off;
- data collection and processing: accomplished in digital format which will enhance analysis.

Alyeska is planning to run the Pipetronix enhanced magnetic flux pig, called a *Magna Scan HR* pig, in the summer of 1991. Early experience with this pig by Pipetronix has exceeded expectations.

Ultrasonic corrosion pig experience

Two successive runs of the NKK ultrasonic corrosion pig in Alyeska's pipeline offer an opportunity to compare results against known pipe conditions. In 1989, Alyeska exposed 6,300 linear ft of buried pipeline, and in 1990 11,800ft was excavated to inspect the condition of the pipeline and make repairs where necessary.

At each pipeline excavation, Alyeska had specific procedures which are prescribed to ensure that all data is collected on the condition of tape, coating, and pipe wall condition. The tape and coating are removed and the pipe wall

Pipeline Pigging Technology

NKK REPORTED		INVESTIGATED		RESULTS		
Metal Loss % of Pipewall	Number of Locations	Wall Loss Found	Number Found Measured	Actual Wall Loss	Number Found	Percent
>40%	4	>40%	4	>40%	1	25
				20-40%	1	25
				10-20%	1	25
				<10%	1	25
20-40%	120	20-40%	81	>40%	3	4
				20-40%	47	58
				10-20%	28	35
				<10%	2	2
				No Data*	1	1
10-20%	289	10-20%	195	>40%	0	0
				20-40%	24	12
				10-20%	114	58
				<10%	46	24
				No Data*	11	6
TOTALS	413		280			

* These locations were field inspected prior to the receipt of the pig data. Therefore, a measurement was not possible for each discrete point indicated by the pig contractor.

Table 3. 1989 NKK data.

is sand blasted to near-white condition, after which the pipe wall is outlined with a grid and measurements of the pipe wall thickness is taken with ultrasonic hand-held detectors and pit gauges.

Upon completion of all measurements and inspection, the pipe is recoated with *Carboline 376* epoxy phenolic, and retaped with Raychem *HTLP-80*; the cathodic protection is reconnected and the pipeline is reburied. Full-encirclement sleeves are installed where a repair is required.

The data collected from these excavations provides for an opportunity to make comparisons with the predicted pig reports. Alyeska prioritizes excavations of the pipeline where pipe-wall thinning and operating pressure provide the least safety margin permitted under the Department of Transportation Code of Federal Regulations, Part 195.

Most of the reported pig anomalies show minimal wall thinning (less than 20%) which would not require pipeline excavation for some time. These

Corrosion inspection of the Trans-Alaska pipeline

NKK REPORTED		INVESTIGATED		RESULTS		
Metal Loss % of Pipewall	Number of Locations	Wall Loss Found	Number Found Measured	Actual Wall Loss	Number Found	Percent
>40%	5	>40%	5	>40%	1	20
				20-40%	2	40
				10-20%	0	0
				<10%	0	0
				No Data*	2	40
20-40%	210	20-40%	109	>40%	2	2
				20-40%	36	33
				10-20%	21	19
				<10%	2	2
				No Data*	48	44
10-20%	686	10-20%	283	>40%	0	0
				20-40%	20	7
				10-20%	79	28
				<10%	36	13
				No Data*	148	52
TOTALS	901		397			

* These locations were field inspected prior to the receipt of the pig data. Therefore, a measurement was not possible for each discrete point indicated by the pig contractor.

Table 4. 1990 NKK data.

anomalies are monitored at each pig run for changes and are used for comparison of pig repeatability and accuracy. Of the data collected from actual field excavations, Tables 3 and 4 reflect the results compared to NKK pig reported corrosion anomalies.

These results are preliminary, as the data is still being reviewed and analyzed; however, some general conclusions on the corrosion status of the Alyeska pipeline can be made.

CONCLUSIONS

1. All Alyeska pipeline corrosion is external and occurs in buried pipe.
2. Corrosion has been most prevalent in areas that tend to be wet.

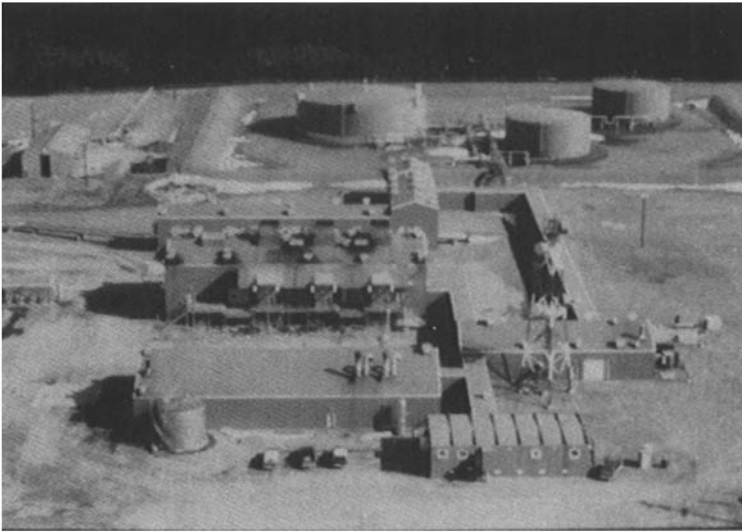


Fig.1. Trans-Alaska pipeline pump station facility.



Fig.2. Corrosion inspection of the Trans-Alaska pipeline.

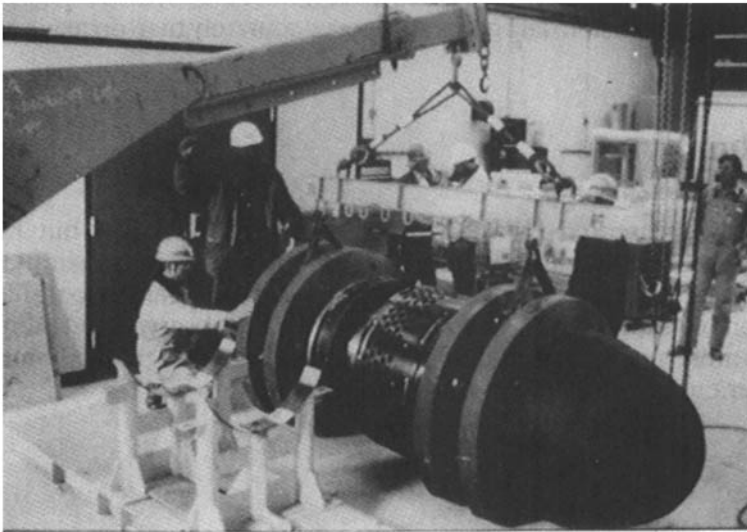


Fig.3. Loading the NKK ultrasonic corrosion pig.

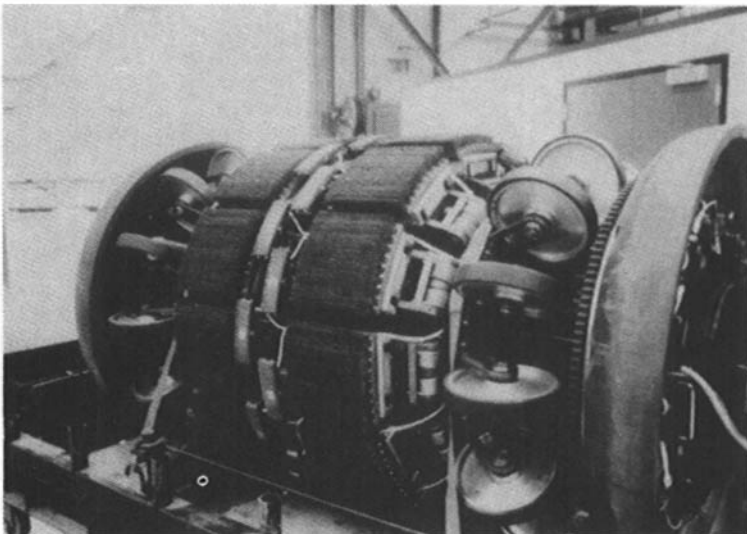


Fig.4. The IPEL magnetic-flux pig.

3. Data collected to date indicates corrosion has been most severe in specific areas of the 800-mile pipeline.

4. Based on the field excavations to date, ultrasonic corrosion pigs provide more specific corrosion data generally more accurately than do magnetic-flux pigs.

Author's note

The data presented in this paper are not final results, but rather a "snapshot" of a continuing process. The data is preliminary and should not be thought of as a final determination. Rather, this data should be considered as indications or trends which need to be continually observed and monitored. Lastly, it must be remembered that this data is limited to the equipment and the experiences within the context of this paper.

ETHYLENE PIPELINE CLEANING, INTEGRITY AND METAL-LOSS ASSESSMENT

THE ALBERTA Gas Ethylene Company (AGEC), in co-ordination with Novacorp International Consulting Inc (Novacorp), successfully performed an intensive internal cleaning and inspection programme on their ten-year old 180-km (110-mile) ethylene pipeline. Throughput in the pipeline had been reduced 26% since start-up due to internal polymer build-up. The internal cleaning and inspection programme was completed (from decommissioning to recommissioning) in 28 days. The programme resulted in the following:

- restoration of the original pipeline capacity;
- increased confidence in the pipeline mechanical integrity;
- experience in pigging operations and increased understanding of the internal deposition phenomenon;
- a good safety record; and
- minimum disturbance to the public.

INTRODUCTION

AGEC operates ethylene manufacturing facilities in central Alberta, Canada. These two ethylene plants are located 20km east of Red Deer, Alberta, at Joffre. They supply two customers near Joffre, and the remainder of the product is shipped 180km by pipeline to other users and cavern storage facilities near Edmonton. The NPS12 (12-in diameter) steel pipeline was put into operation in 1979, and typically operates at near 9000kPa (1200psi) and 5°C (40°C). In 1989, after 10 years of operation, AGECE decided to perform an

internal inspection of the pipeline to verify its mechanical integrity.

BACKGROUND

The following were the primary reasons for the inspection:

Public safety - a need for AGEC to determine the line's mechanical integrity given its concern for public safety.

Pipeline coating concerns - the pipeline is coated with double-wrap polyethylene tape which is prone to disbondment. Disbondment is difficult to detect, and corrosion under the disbonded coating is only detectable with an internal inspection tool.

Polymer formation - during the life of the pipeline, maximum throughput had decreased by 26%. This decreased capacity seriously affected AGEC's product transfer capability such that it would force a reduction in ethylene plant production under certain circumstances. In order to perform an internal inspection, the pipeline polymer had to be removed.

Project considerations

Because of the uncertainties associated with the internal polymer, coupled with the requirement to evacuate the line to install additional pigging stations, the actual cleaning and inspection was to take place coincident with an ethylene plant maintenance shutdown. The pipeline was completely decommissioned, with all pigging taking place in nitrogen. This not only eliminated the risks associated with sticking a pig in ethylene service, but also eliminated the prospect of inadvertently interrupting ethylene supply to customers. The length of the project was set at 28 days, the time planned for the ethylene plant turn-around.

PROJECT ORGANIZATION

To provide pigging experience, Novacorp was hired to engineer, procure and construct the capital works and to clean and inspect the pipeline. AGEC

Ethylene pipeline cleaning

was responsible for the decommissioning and recommissioning and the handling of all community awareness, safety and environmental concerns. The project plan was based on the recommended course of action taken from an engineering report prepared in 1988 by Novacorp, which compared various methods of establishing the mechanical integrity with associated costs.

PREWORK

The prework phase included all the work necessary to ensure the work scope was completed safely and successfully within the 28-day outage. Procedures were written, manpower selected and trained, the field sites prepared and the piping assemblies prefabricated. This was difficult, considering:

- AGEC had little experience in decommissioning or recommissioning its 12-in pipeline;

- no company had successfully internally-inspected an entire ethylene pipeline;

- the polymer problem was not clearly understood. Decisions were based on pressure-drop information and polymer samples retrieved in filters. Consequently, AGEC relied heavily on the experience of other ethylene pipeline companies and pigging contractor expertise to develop the cleaning programme.

PROJECT PLANS

Decommissioning

Based on successful decommissioning of other pipelines, and in order to meet the tight schedule, it was decided that the decommissioning process would be carried out by using nitrogen to displace the ethylene at normal operating conditions. The nitrogen/ethylene interface would travel at 1.1 m/s (2.5 mph) to maintain fully-turbulent ethylene flow and to reduce the inter-

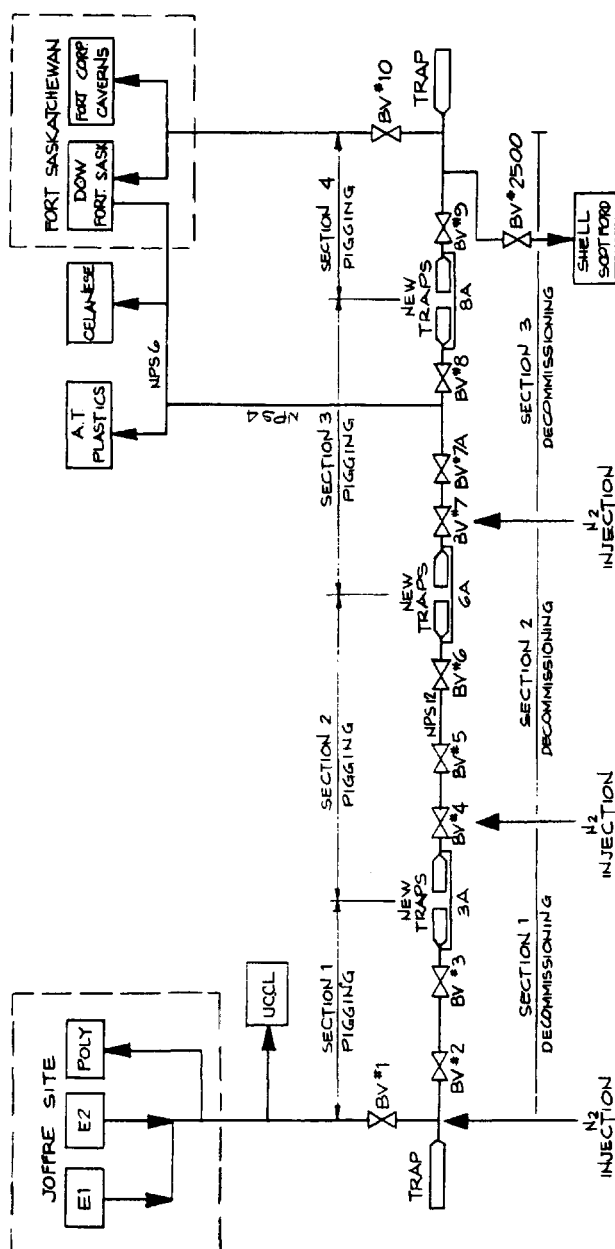


Fig.1. Pipeline schematic with modifications.

interface length of contaminated ethylene. To expedite the process, decommissioning was done in three stages with three nitrogen injection points (see Fig.1). Nitrogen injection would begin at the south end of the pipeline; as the interface passed the next injection site, the previous section was shut in, depressured, and prepared for capital work. Due to the amount of nitrogen involved in decommissioning, it was necessary to use three nitrogen service companies, each with one injection point.

Capital works

In order to clean and inspect the entire 180-km line in a 28-day period, the pipeline had to be separated into four sections. The section lengths were set at 75km, 51km, 35km, and 19km, based primarily on the amount of polymer expected in each section. The deposition problem was considered to be more severe at the north end of the line, which is furthest from the plants, than at the south end, so the section lengths decreased proportionally. Each section had its own launch and receive traps, as well as facilities to separate the polymer from the nitrogen. Four simultaneous pigging operations proceeded on a 24-hour-a-day basis.

For capital works, Novacorp was retained to design, procure, fabricate and install all additional pig trap sites complete with polymer-separation systems. The receive sites had separation facilities to remove any debris from the nitrogen stream as it was vented to the atmosphere. These consisted of a separator/knock-out drum, pressure let-down valve and final filtration bags (see Fig.2).

Cleaning and inspection

Cleaning commenced immediately upon completion of the capital works for a section. All cleaning and inspection tools were propelled by nitrogen, with their speed governed by a control valve at the receive sites. The proposed schedule of cleaning and inspection runs is shown in Fig.3; this selection of pigs was designed to progressively remove the polymer debris from the pipe wall and successfully carry it out to the separator and filter bags.

The cleaning programme assumed the majority of polymer would be removed during the 1400-kPa (200-psi) runs when the separator was in service. The separator would then be by-passed for all inspection runs, when pressures were 3500kPa (500psi).

The four sections were totally independent for cleaning. Each had dedicated resources with operations proceeding 24 hours a day.

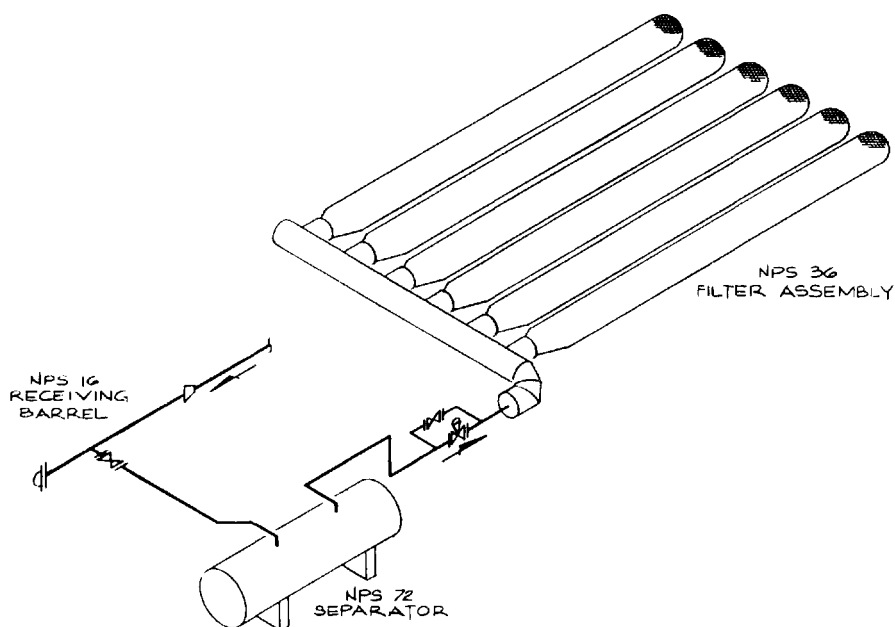


Fig.2. Filter detail.

Nitrogen for the four sections was supplied by three nitrogen service companies trucking nitrogen from three nitrogen production facilities.

Recommissioning

Once the pipeline was cleaned and inspected, it was recommissioned as quickly as possible with minimal loss of ethylene product.

The final recommissioning procedure was as follows:

1. The pipeline pressure was increased to 300-350psi (2100-2500kPa) by venting or injecting nitrogen (whichever was required) to prevent subcooling (of piping and valves) and to decrease the potential for ethylene decomposition.
2. Ethylene was introduced through a sacrificial by-pass valve while maintaining 7500kPa supply pressure to the south end users.

Ethylene pipeline cleaning

CLEANING

- (i) Scout Pig (25% gauge plate)
- (ii) Pressure bypass with flexy conical cups
- (iii) Pressure bypass with standard conical cups and one disc
- (iv) Pressure bypass with hard conical cups, two discs, magnets and brushes
- (v) British Gas brush tool at 200 psi
- (vi) British Gas brush tool at 700 psi

INSPECTION

- (i) Enduro Caliper / Bend Tool
- (ii) Profile Tool
- (iii) British Gas Corrosion Tool

Fig.3. Proposed selection of pigs.

3. Nitrogen was vented at BV10 (north end) to maintain pressure at 300-350psi in the pipeline. Vent streams were analyzed continually for ethylene with portable gas chromatographs.
4. Monitoring continued until product-quality ethylene was seen (less than 300ppm N₂). The flares were activated at 6% ethylene and stopped when product ethylene was seen.
5. At this point, flaring was stopped to allow pipeline pressures to increase to normal operating pressures.
6. When the differential pressure was less than 200kPa (30psi) the isolation valves were opened and the pipeline put back into service.

Safety and public relations

All 300+ workers involved in the project completed a thorough project safety indoctrination which detailed all the project safety rules and safety guidelines. The project goal was to have no recordable injuries.

A paramedic crew was contracted to patrol the pipeline 24 hours a day in case of injury.

All landowners along the pipeline were contacted by mail three months prior to the project commencing, informing them of the project. Two weeks

Pipeline Pigging Technology

	INTERVAL DISTANCE (KM)	TRAVEL TIME (HR)	AV. VELOCITY KM/HR	INTERFACE LENGTH (KM)
BV 1 - BV 2	27.2	7.25	3.82	1.35
BV 2 - BV 3	18.5	4.75	3.89	1.35
BV 3 - BV 4	27.5	7.1	3.87	1.37
BV 4 - BV 6	30.8	8.1	3.80	1.39
BV 6 - BV 7	26.9	7.0	3.84	1.47
BV 7 - BV 8	17.4	4.3	4.04	1.45
BV 8 - BV 9	14.0	3.2	4.375	1.53
BV 9 - BV 10	14.5	3.6	4.02	1.73

Fig.4. Interface log.

prior, visits were made to the landowners within a one-mile radius of a work site to highlight any work activities which affected the area, and to answer any questions and concerns they had.

PROJECT EXECUTION

Decommissioning

Decommissioning commenced at 12.00 noon on Sunday 13th May, 1990. A nitrogen injection rate of $510\text{sm}^3/\text{hr}$ was selected, based on a theoretical calculation to maintain an interface velocity of 1.1m/s for fully-turbulent flow. Target nitrogen injection rates were initially restricted by a high pressure drop through a 2-in injection valve on the pipeline. Injection then stopped to connect to a second injection point. After approximately one hour, nitrogen injection recommenced, and rates of $510\text{sm}^3/\text{hr}$ were achieved. Fig.4 shows the actual times for the interface to reach each block valve site, and the corresponding length of the interface as measured.

The nitrogen front reached the north end of the pipeline (BV10) in 45.3hrs, with an interface length of 1.7km. The contaminated ethylene was flared using a combination of portable flares and a permanent flare.

Ethylene was successfully purged from the three southern sections. A second, low-pressure, sweep of nitrogen was required on the north end when ethylene was detected prior to cutting into the line. It is believed this ethylene vapour was released from the polymer build-up in this section following a rest

period at low pressure. A second low-pressure purge was successful in removing all residual ethylene, and capital works commenced after a delay of 12hr.

Capital works

When decommissioning was complete on a section, capital works began immediately. Maximum piping prefabrication and site assembly had been done prior to the outage, leaving only the actual pipeline tie-ins. These tie-ins were completed with very few problems. The first section was ready for cleaning on day 4, and the last section was ready on day 10 of the shutdown.

The initial cut-outs of the pipeline clearly revealed the polymer build-up in place. A thin film, 1-2mm thick, of slightly sticky and very cohesive low-grade polyethylene was observed. It could easily be wiped off the pipe with a simple rub of the hand.

Cleaning operations

The first cleaning pig in the line determined that the polymer was extremely easy to remove from the pipe wall. Although several progressive cleaning runs were planned, it was found that the 'scout' pig removed virtually all of the polymer. Even modified with more by-pass holes and notched cups, the scout tool continued to remove the majority of the polymer. In fact, the compacted polymer carried in front of the pig created too much of a barrier, and resulted in two stuck pigs and pipeline cut-outs. Lost time was quickly regained, however, by omitting some of the proposed cleaning runs. It was found that, following the initial pig run, the line was effectively clean and did not require as extensive a programme as originally anticipated.

Fig.5 gives a listing of the cleaning tools per section, with pressures, speeds, and comments.

Inspection operations

Inspection operations comprised a calliper vehicle, a profile vehicle, and the corrosion inspection vehicle.

All calliper vehicles completed their runs without major incident, and no bend or diameter restrictions were identified. The profile vehicles also ran successfully, and further confirmed that the inspection vehicle should have

SECTION	DATE	RUN #	DESCRIPTION	PRESSURE (kPa)	AV VEL. (km/hr)	DEBRIS REMOVED	COMMENTS
1	May 16	1	Scout Pig - 4 flexi cups 2-1/8" bypass holes	1400 (200 psi)	to BV 2 to BV 3	wire brush, 0.75 m3 compacted polymer	Tool became stuck in heavy wall at BV 3.
1	May 18	1A	Modified Scout Pig - 4 flexi cups (2 slotted) 4-1/8" bypass holes	1400	unknown	unknown	Tool was relaunched at BV 3, lost from tracker until received at pig trap.
1	May 21	2	Scout Pig	1400	12.4	handful of polymer	No problems.
1	May 22	3	Pressure bypass pig with brushes towing magnetic assembly	1400	11.5	nothing	No problems.
1	May 22	4	British Gas Cleaning Tool	1400	10	Nothing	No Problems.
2	May 18	1	Modified Scout Pig	1400	8	1 m3 of compacted polymer	Tool entered receive trap at high speed compressing debris against door.
2	May 18	2	Scout Pig	1400	10	Small amount of debris	No problems.
2	May 20	3	Pressure bypass on four cups	1400	10.5	Dust	No problems.
2	May 21	4	Pressure bypass with brushes towing magnetic assembly	1400	9.8	Small amount of ferric dust	No problems.
2	May 22	5	British Gas Cleaning Tool	1400	10	Nothing	No problems.
3	May 21	1	Modified Scout Pig	3500 (500 psi)	10	0.75 m3 at polymer	Separator was bypassed to allow higher line pack. No problems.
3	May 22	2	Scout Pig	1400	9.7	Dust	No problems.

Fig.5. Summary of cleaning runs.

Ethylene pipeline cleaning

SECTION	DATE	RUN #	DESCRIPTION	PRESSURE (kPa)	AV VEL. (km/hr)	DEBRIS REMOVED	COMMENTS
3	May 23	3	Pressure bypass pig with brushes towing magnetic assembly.	1400	8.1	Ferric dust	No problems.
3	May 23	4	British Gas Cleaning Tool	1400	10	Nothing	No problems.
4	May 22	1	Modified Scout Pig	3500 (100 psi)	10 to BV 2500	1.25m ³ of compacted polymer	Separator was bypassed to allow high line pack. Tool ran smoothly until 1 km from receive trap where it stuck in heavy wall pipe at takeoff tee.
4	May 24	1A	Modified Scout Pig	3500	10.9	Handful of debris	No problems.
4	May 24	2	Scout Pig	1400	10.4	Dust	No problems.
4	May 24	3	Pressure bypass pig with brushes towing magnetic assembly.	1400	9.8	Ferric dust	No problems.
4	May 25	4	British Gas Cleaning Tool	1400	10	Nothing	No problems.

Fig.5. Summary of cleaning runs (continued).

Pipeline Pigging Technology

	SECTION 1	SECTION 2	SECTION 3	SECTION 4
CALIPER/BEND TOOL:				
Date	May 23	May 22	May 24	May 25
Pressure (kPa)	3500 (500 psi)	3500	3500	3500
Vel. (km/hr)	8.0	8.0	8.0	8.0
Comments:	No problems	Bend chart recorder malfunction	No problems	No problems
BRITISH GAS PROFILE TOOL:				
Date	May 23	May 25	May 24	May 28
Pressure (kPa)	3500	3500	3500	3500
Vel. (km/hr)	10.5	9.0	8.8	8.0
Comments:	No problems	No problems	No problems	No problems
BRITISH GAS INSPECTION TOOL:				
Date	May 24	May 24	May 28	May 28
Pressure (kPa)	3500	3500	3500	3500
Vel. (km/hr)	10	9.0	9.0	8.8
Comments:	4 sensors had broken off the sensor ring however, data was retained. Tool had hung up just out of launch trap in bypass tee.	3 sensors had broken off when tool became stuck in bypass tee but again the data was retained.	No problems	No problems

Fig.6. Summary of inspection runs.

safe passage. However, problems did occur for the corrosion vehicles due to some heavy-wall tees with internal diameters less than the allowable. Indications are that the calliper log did indicate the restrictions; however, more careful interpretation would have been required to highlight these. Likewise for the profile tools; it was a difficult task to determine what was normal wear on the gauge plates and what was the result of a mild diameter restriction. Particular care must be taken to evaluate all the information thoroughly and collectively.

A nitrogen line pack of 3500kPa was used to prevent tool surge. This is somewhat lower than at first thought necessary, yet it proved to work consistently well for all inspection runs. Only one velocity excursion was

encountered, attributable to the restrictive tees. A summary of the inspection runs is presented in Fig.6.

Recommissioning

Pipeline recommissioning commenced on day 24. Pigging was complete on 20th May, leaving 8 days for leak checking and maintenance work. On day 23, the pipeline pressure was increased to 2300kPa (330psi), and ethylene vapour was introduced at 23,000kg/hr. Venting took place at BV10 (north end) to maintain pressure in the pipeline. The vent stream was analyzed by portable gas chromatograph to detect the ethylene/nitrogen interface. It took 28 hours for the interface to reach the north end of the pipeline. At this point, the vent stream was flared until product-quality ethylene was detected. This took an additional four hours. Flaring was then stopped and the line was allowed to pressure-up to operating pressures. The pipeline was put back into service on 12th June, 30 days after shutdown operations began.

PROJECT RESULTS

Pipeline capacity

Calculations from pressure-drop readings taken after the pipeline was put back into service revealed that the pipeline capacity had been restored to 160,000kg/hr (an increase of 26%). This was confirmed in August, when pipeline flows reached 157,000kg/hr without maximum operating pressure limits being exceeded. Fig.7 lists friction factor ratios before and after cleaning.

Pipeline integrity

Results from the inspection revealed only five reportable defects (more than 20% metal loss) along the entire 180-km (110-mile) pipeline. The maximum depth reported was 34% metal loss. Novacorp performed an engineering critical assessment on the data, and determined that no immediate repairs were required. AGEC will excavate, inspect and recoat these defects over the next two years.

Pipeline Pigging Technology

BV	APRIL '90	JUNE '90
1 - 2	1.60	0.8
2 - 3	1.30	0.76
3 - 4	1.20	0.83
4 - 6	1.45	0.83
6 - 7	1.91	0.94
7 - 8	1.59	0.81
8 - 9	1.61	0.86
9 - 10	3.24	0.94

PRESSURES

	APRIL '90	JUNE '90
Typical Pressure Drop (100 Mgs/hr)	1300 kPa	380 kPa

Fig.7. Friction factor ratios.

Polymer quantity

The estimated amount of polymer removed from the pipeline was 5m³. This estimate includes polymer removed from cut-outs, separators, and filter bags. All of these held polymer in different forms, some loose, some compacted, making an accurate volume estimate difficult. The amount of polymer removed supports the estimates generated from roughness calculations prior to the cleaning. AGEC will continue to monitor polymer build-up using

Ethylene pipeline cleaning

pressure drops, friction factor comparison, and roughness calculations. Removable test spool pieces will be installed on the pipeline to further monitor the deposition rate. A long-term objective is to better understand the polymer formation mechanism.

Future programmes

With this project's successful conclusion and the restoration of pipeline capacity, AGECE will be investigating a future on-line ethylene cleaning programme to maintain pipeline capacity. Corrosion rate predictions determined by Novacorp are presently being analyzed to develop an inspection programme that will ensure a continued high level of integrity is maintained.

Safety and public relations

Great efforts were made on this project to provide a safe work environment and promote good public relations.

One minor recordable injury resulted during the 60,000 man-hours of work, and two public complaints were received.

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PIPELINE ISOLATION: AVAILABLE OPTIONS AND EXPERIENCE

IN EARLY 1989, new guidelines were introduced to the North Sea oil and gas industry covering the requirement for and positioning of top-of-riser ESD valves. The purpose of these valves is to prevent loss of product from the pipeline in the event of topsides' failure, etc.

As such, many operators had to look at either fitting new valves or repositioning existing valves. In order that this work can be undertaken in a safe environment, there are two basic options:

- i) displace all the product from the pipeline with an inert medium, usually either water or nitrogen gas;
- ii) provide localized isolation close to the worksite which would leave the work area safe whilst leaving most of the pipeline full of product.

The options available for doing this and the method of determining the most suitable solution depend upon a number of factors:

type of product;
length and diameter of the line and hence volume of product involved;
facilities for disposal of product;
time available for operations;
space availability at operational location restricting equipment deployment.

Bearing these factors in mind, various scenarios can now be considered, and the advantages and disadvantages of alternative solutions examined.

OIL LINES

Oil pipelines represent a simple problem when compared to gas lines. Firstly, the volume of product required to depressurize the line is very small, meaning we can work with a totally-depressurized system without wasting product. Secondly, if the line is decommissioned and flooded with water, there are very few problems associated with re-commissioning, as the water can usually be handled in the production facilities.

The options for oil lines are therefore relatively straightforward, and depend usually on the volume of product involved.

For lines of small volume, the simplest solution is to displace the product with water, allowing the work to take place under safe conditions. Even when all the product has been displaced, it is prudent to utilize a low-pressure isolation device in the form of a sphere or stopper to ensure that any vaporisation of hydrocarbon from wax, etc., does not come into contact with the worksite, particularly if welding is going to take place.

For larger-volume systems, the pipeline can usually be isolated locally to prevent having to displace all the product from the line. This can be done by displacing one or more pigs down the riser and onto the seabed with water. It is important in this scenario to evaluate the differences in elevation of the two ends of the line, taking into account the differing static heads caused by having one end of the line full of oil and one full of water. Again a secondary isolation is usually installed after cold cutting at the new valve location and prior to welding.

Under both of these scenarios, testing of the completed works is easily undertaken by hydrotesting. In the second case, this can be carried out with the isolation pig still in position so that product is still kept well away from the new works being tested.

On completion of the work, the pig can be displaced back to the worksite by displacing with oil from the far end or, by launching another pig, the train can be pushed out to the far end.

GAS LINES

On gas lines, the problems associated with the valve installation are much greater. Firstly, we have to vent off large quantities of gas to reduce the pressure in the line. Secondly, if we introduce water into the line, we have in most instances to dry the line in order to recommission it, in order to prevent

hydrate formation and minimize corrosion. This is both costly and time-consuming. It is therefore only really feasible to flood and commission short pipelines of small diameter.

Nitrogen purging the pipelines can also be very expensive on larger sizes of line. Due to vaporisation of condensate, etc., even this doesn't guarantee to make the line perfectly safe. A local isolation is usually required, again in the form of a sphere or stopper, to prevent vaporised liquids coming into the worksite area.

The alternative to this, particularly on longer trunklines, is to carry out a local isolation. Several techniques have been examined for carrying out this type of isolation, including: tethered inflatable stoppers and bags inflated by an umbilical, remote-controlled stopper pigs, and high-differential high-sealant pig trains.

McKenna and Sullivan has had particular experience with the high-differential pig train, which has been used successfully on several operations.

The concept of the high-differential pig train was specifically developed to meet the needs of operators requiring this localized isolation. Due to the short time period available on the first project where this was used, the pig train was decided upon because insufficient time was available for development and manufacture of other systems.

The pig-train concept was seen as utilizing proven basic technology in the form of bi-directional pigs and with an in-built factor of safety due to the number of pigs being used. Trials were carried out to develop two types of pigs: (a) a high-sealant pig to provide the main gas interface, and (b) a high-differential pig to provide a factor of safety in the event of either inadvertent pressurization of the line or rupture of the line which could cause it to fill with water and pressurize.

A test loop was built to simulate conditions in the pipeline. This consisted of a section of light-wall pipe, a section of heavy-wall pipe and a 90° bend. Various disc configurations were tested on a standard bi-directional pig body. Different oversized discs were used in varying configurations to try to achieve the best combination of either sealing characteristics or high-differential characteristics without damaging the discs or the pig body. Many combinations were initially tested, from the original bi-di configuration up to the point where the force across the pig was so great that the discs tore under the stress. Eventually an optimum disc configuration was found, where no damage occurred to the pig and the maximum differential pressure (DP)/sealing capability was achieved.

Subsequent testing of pigs on other pipework systems has led to further development of this initial concept. Unfortunately, from the operator's point of view, it has become clear that the suitability of a particular pig for providing high DP is unique to the size of pipe involved and the difference in wall

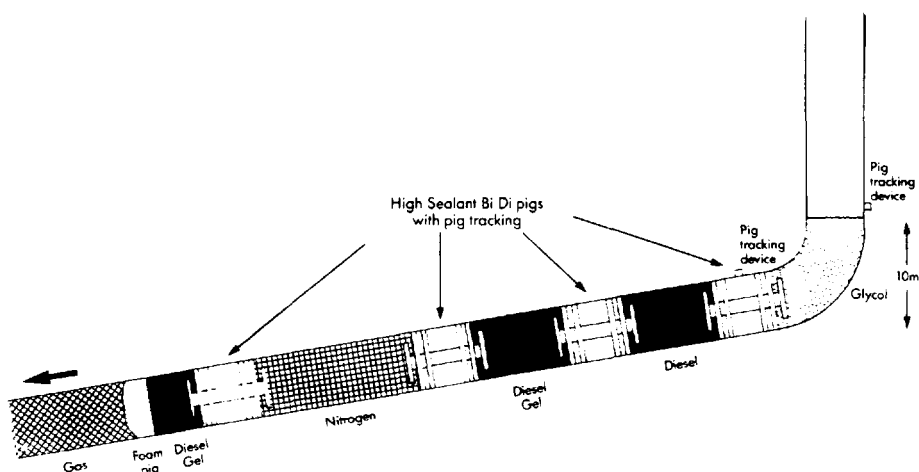


Fig.1. Primary dynamic seal - intended pig train position.

thicknesses. For example, a high-DP pig developed for 24-in pipe will not give similar results at 36in, because the area of contact on the pipe wall changes, the relative distance between the disc support flange and the pipe wall is different, and hence the deformation of the disc is altered.

Differing wall thicknesses have an even more marked effect on DP capability as one might imagine. DP's obtainable in pipe of constant bore are more than halved in the pipe configurations where we have a ½-in difference in wall thicknesses due to the damage caused by heavier-wall pipe.

If reproducible results are required in the field, then tests will be required to establish the particular figures for a given set of pipeline parameters.

On this initial topsides' isolation, the pig train was designed using the following parameters:

- i) the front part of the train would aim to provide the main interface to prevent migration of gas towards the worksite;
- ii) the second part of the train would provide the differential holding capability which would provide a large factor of safety in the event of inadvertent pressurization or pipeline rupture. This would be achieved by two means; firstly by using high-DP pigs, and secondly by using slugs of liquid between the pigs to create a static head should the pig train start to move up the riser.

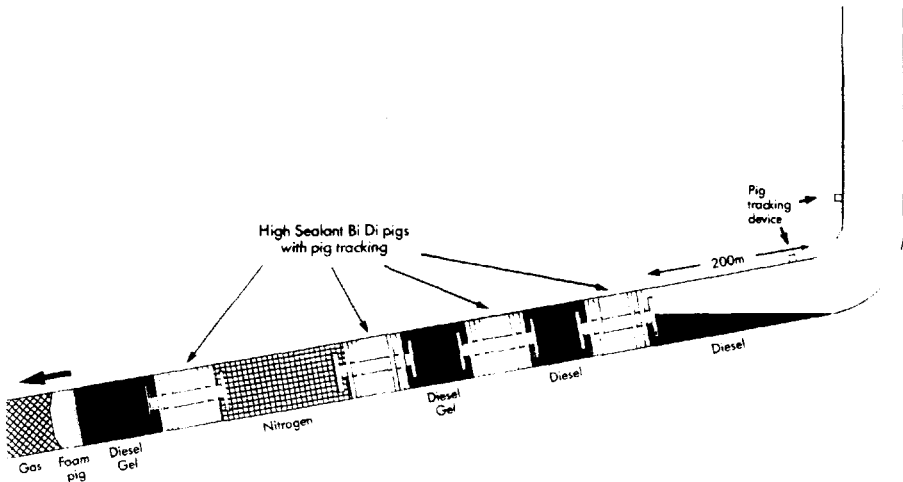


Fig.2. Primary dynamic seal - actual pig train position.

With this in mind, the following pig train was developed (see Fig.1). Due to the short period of time involved, only four pigs were available from the client, and there was no time to order additional pigs. Consequently, a foam pig was used at the front of the train. This was simply to contain a slug of diesel gel which would increase the sealing efficiency of the first pig. A large slug of nitrogen would then provide an inert buffer to minimize the risk of any gas diffusing through to the second half of the train. The second portion of the train was made up of three high-DP pigs, separated by slugs of liquid.

The first of these was diesel gel to increase sealing efficiency, and the second was diesel. The length of these slugs was calculated to give 90 linear metres of liquid, or approximately 7bar of head.

It was intended that the pig train should be positioned just beyond the bottom riser bend. A slug of glycol would then be injected, such that the level of glycol could be closely monitored in order to detect any movement of the pig train. In practice, this proved difficult to achieve, as the varying speed of the pig train when propelled with nitrogen did not allow sufficient control of the train. However, this did not affect the efficiency of the pig train or the outcome of the operation.

After launching the pig train into a fully-depressurized line and venting-off the pressure behind the pigs, the pig train was allowed to stabilize before cold-cutting the line. A secondary barrier in the form of a modified sphere with bypass monitoring facilities was then installed prior to the welding work beginning. The Pipelines Inspectorate's requirements for testing of the new

works had a significant impact on the way the valve assembly was installed. These indicated that all flanged joints should be leak tested at 1.1 MAOP, whereas a minimum number of new welds could be inspected by 100% NDT. This meant that in order to avoid pressure testing the whole line, the flanged valve had to be pre-tested with flanged pup pieces already in place, rather than welding-in the two flanges offshore and then bolting in the new valve.

In practice, the differential pressure across the pig train in the offshore phase was slightly less than that anticipated from the trials; this may have been due to condensate present in the line. The pressure required to 'flip' the entire train to return it back to the platform on completion of the operation was 10.8 barg. Combined with the static head of diesel available, this meant that the pig train would have held back a DP of up to 18 barg.

SUBSEA VALVES

Following the success of the high-DP pig train for pipeline isolation for topsides' valve installation, its application for subsea valve installation was studied. The application for subsea works introduced several new factors into the pig train design concept.

Firstly, because the construction work would be carried out subsea, it was necessary to launch the pig train with water to provide the necessary working environment for the divers. This would be advantageous for control and positioning of the pig train, as water is largely incompressible and easy to meter. It would, however, mean that some method of recommissioning the pipeline would be required.

The design premise for the pig train was also altered by the construction work being subsea. It was always intended that the pipeline would be vented down to static head pressure subsea, i.e. approximately 13 bar. With the pig train in position and the pipeline cut, the pig train would be in dynamic balance, with 13 bar gas pressure on one side and 13 bar static head on the other.

The differential pressure capability of the pig train would only come into play in an emergency situation. Initially, this was taken to be inadvertent pressurization from the far end with gas moving the pigs towards the divers. However, this was found to be highly unlikely as, in this case, gas injection was not possible. Further examination of the system gave a worst-case scenario of a topsides' leak or rupture at the far end leading to pipeline depressurization.

The full static head would then be acting across the pig train, and the divers could potentially be sucked into the pipeline if the pig train moved. It was

therefore decided that the pig train should be designed to hold the full static head pressure (13 barg) plus a factor of safety. Due to the cumulative nature of the DP across the pigs, the factor of safety required can be relatively low, because in losing one pig, for example due to damage, we only lose a small percentage of the entire system's capability. The design requirement for the pig train was therefore set at 15 barg.

The use of nitrogen within the pig train also required careful consideration. Whilst slugs of nitrogen were desirable to minimize diffusion of gas along the train, their use would create other problems. When launching the pig train for topsides' isolation into a pipeline at zero pressure, it had been possible to vent off the residual nitrogen pressure after launching the first two pigs. Launching the second part of the train had only compressed this to approximately 0.1 barg.

In the subsea case, this would not be possible when launching against a pressure of 13 barg. The nitrogen slugs would therefore act as springs with the potential of pushing the pig train back towards the worksite after reducing the launch pressure to static head pressure.

Examining the pressure profiles across the pig train, and the positioning of the nitrogen slugs, became an important part of developing the pig train.

With a ½-in difference in wall thickness between thick- and thin-wall, the DP capability of the pigs was relatively low. A comprehensive testing programme was undertaken to evaluate the effect of wear on the pigs and long-term liquid retention capability, as well as disc material compatibility tests with the various fluids with which the pigs would be in contact (bearing in mind contact could last up to 60 days).

The pig train was designed with three pigs at the front, separated by slugs of nitrogen. Again, the main purpose was to minimize the diffusion of gas towards the worksite. These were then followed by four slugs of recommissioning fluid trapped between high-differential pigs; a further eight high-differential pigs separated by slugs of inhibited water would complete the train. A standard bi-di would be added at the rear of the train to remove the hyperbaric spheres on the way out. The lengths of all the liquid slugs were sized to give the necessary spacing when receiving the train, to ensure that none of the train left in the line would be in the other ball valves.

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PART 3

PIGGING TECHNIQUES AND EQUIPMENT

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THE HISTORY AND APPLICATION OF FOAM PIGS

WHEN A pipeline operator contemplates pigging a line, he must take several factors into consideration:

- the purpose of pigging
- the operating conditions of the pipeline
- the design of the system
- the risks involved
- the types of pigs available

If the operator is faced with conditions such as the removal of large deposits of paraffin or scale, low pressures and flows, multi-dimensional lines, reducing valves, or perhaps a "lose my job if I get a pig stuck" situation, then the selection of pigs becomes an important decision. A list of available pig designs is unfortunately not very long. The highlighted choices are spheres, cup/disc pigs with steel or urethane mandrels, gels, and foam pigs. This paper reviews the definition, history, various designs, and some of the unique applications of the foam, or 'Polly Pig' as it is commonly called, and why it may be the most versatile tool available to the operator.

WHAT IS A POLLY PIG?

In function, the polly pig is like most other non-intelligent pipeline pigs. It is propelled through a pipe by a liquid or a gas, and performs work such as dewatering, cleaning, or product separation. The body of the pig is made from a special urethane foam that is flexible and wear-resistant. The open-cell foam structure allows for the equalization of pressure throughout the foam body. It can conform to dimensional reductions and pigging obstacles that may prohibit the safe passage of other pigs. An elastomeric coating, similar to the urethane material used for cups and spheres, can be applied to the external

surface-bearing area (that part of the pig that touches the pipe wall) to add wear resistance and sealing ability. Abrasive surfaces such as steel wire brushes can be added to increase the cleaning and scraping ability.

HISTORY

It is not certain when the first flexible foam pig was put into a pipeline, or who came up with the idea. The first recognized foam pig was patented (Wheaton) in 1954 for use in the dairy industry. A low-density foam cylinder (resembling furniture cushion material) was inserted, under a vacuum, into the milking system, displacing the liquid and making the cleansing process more efficient. On one end of the cylinder a thin layer of rubber gasket material was applied to act as a seal against the vacuum. The coated cylinder, or "swab" as it became known, was also used in pressurized pipe applications. Although it worked well for light cleaning and drying in short length lines, it had a tendency to break apart, and thus had a limited use.

In 1960, a major oil company required a flexible pig that would remove a build-up of anaerobic bacteria in a water-injection system constructed from transit pipe. The short-radius 90° bends contained in the system would not allow successful passage of a sphere or mandrel pig, and the low-density swab would not clean the deposits sufficiently. The oil company enlisted the help of a firm that was involved in manufacturing packaging materials and other products from a new polyether, open-cell foam system. The material was nearly as flexible as the soft foam used in swabs, but had a greater tear strength and firmness. The higher-density foam was moulded in the shape of a bullet. The nose of the pig was parabolic, to help negotiate the bends, and the base was concave similar to the back side of a cup, to assist in sealing. Called the 'Polly Pig', it negotiated the system and removed the deposits from the pipe wall without losing a seal or plugging in the tight bends.

The next stage in the evolution of the polly pig was the addition of an external coating. The foam systems available in the 1960s were not very durable and had a tendency to wear quickly and break apart under the stressful conditions found in cross-country pipelines. To strengthen the foam, a flexible, polyurethane elastomeric coating was applied to the exterior of the foam body. The base was coated to minimize by-pass through the pig body, and the nose was coated to resist wear when the pig negotiated bends in the pipeline. The surface bearing area of the foam body was covered with a spiral pattern of the coating to give the pig greater wear resistance and wipe the pipe more efficiently. In an effort to increase its sealing ability, another series

of spiral bands was applied in the opposing direction, forming a criss-cross pattern. With the differential pressure pushing the oversized pig forward, the opposing frictional drag caused the cleaner to "swell" slightly and increase its' force on the pipe wall. (This relates to the Kellem Anchor theory, more commonly known as the secret behind the ancient Chinese finger puzzle.)

In order to increase cleaning ability, the ends of toothbrushes, containing the plastic bristles, were moulded along the exterior of the pig body and provided us with the first abrasive polly pig. The second generation of brush pigs used the strips of plastic bristles from "TONI" hair curlers. The addition of these brushes helped the pig remove soft deposits on the pipe wall, but still were not abrasive enough for harder scales. This lead to the addition of silicon carbide grit and emery cloth embedded along the surface of the pig.

The polly pigs of the 1960s still were only considered for light cleaning and drying. The ether-based foam systems of this era were structurally not very strong, would not travel long distances and did not hold up well when used with hydrocarbons. With the advances made in polyurethanes over the last 20 years, the polly pig has become a more durable cleaner with many uses. Urethane foam bodies are now manufactured from ester and ether/ester blends, giving them the ability to withstand most hydrocarbons and chemicals, and to have exceptional tear strength properties while still maintaining flexibility. Improvements in the cell structure have increased its ability to "breathe", allowing the foam to be used in higher pressure applications. Additionally, the urethane coatings and abrasive coverings have become stronger and more aggressive.

SPECIFICATION AND DESIGN

Polly pigs are manufactured in many designs and sizes. Most are in the shape of a bullet with an elastomeric coating on the base to provide for maximum seal against the propelling force. Some have coating on the surface to enhance the sealing and wiping capability of the pig, and to increase its wear resistance. Other styles have special abrasive materials to aid in cleaning and scraping. Normally, the overall length of the pig is 1.75-2 times the pipe diameter, with the base-to-shoulder (the point where the surface bearing area begins to taper towards the nose) dimension measuring 1.5 times the diameter. Polly pigs are currently manufactured in diameters from 0.25in to 108in, with increments of 0.125in available in diameters under 12in.

The foam body is made by mixing several urethane resin components together, under controlled conditions; the mixture is then poured into a

mould. As the resins chemically react, the mixture rises like cake dough as gas molecules are released. It is the combination of the material rise and gas pockets that forms the open-cell structure. The "walls" of each cell are flexible and give the finished foam its compressibility and memory. Polly pig foam can be classified into three groups based on the density range:

Low density (swabs)	1-4 lb/ft ³
Medium density	5-7 lb/ft ³
High density	8-10 lb/ft ³

The numeric densities are calculated by a weight/volume ratio and can be somewhat misleading. It is suggested that one looks at density in terms of firmness. The lower the density, the softer the foam; the higher the density, the firmer the foam.

Each of the density ranges offers a different flexibility and wear resistance, the lower density being more flexible and subject to wear than the higher density. The elastomeric coatings on the pig bodies are colour coded to help distinguish between densities. Normally, either a blue or red/orange coloured coating identifies the medium density foam and crimson or scarlet is used for the higher density foam.

Normally, the coatings are made from 70-90 Shore A durometer urethane elastomer and are applied by hand. The hardness of the coating will determine its flexibility and wear resistance, and as with the foam, the more flexible it is, the more it will wear. The thickness of the coating is usually 0.125-0.25in depending on the pig's diameter.

Abrasive materials can be attached to the surface of the foam body by means of the urethane resin. Wire brush (steel, brass or plastic) straps, silicon carbide grit and other materials increase the scraping ability of the pig.

COMMON TYPES OF POLLY PIG

There are numerous designs of foam pigs available, but the most frequently used are:

Swabs - low-density foam with base coated for a seal. Used for removal of soft materials, drying, absorption of liquids (a swab can absorb up to 75% of its volume in liquids, such as water);

Bare squeegees - medium- or high-density foam, coated base. Used for drying, dewatering and light cleaning;

Foam pigs

Criss-cross - medium- or high-density foam with coating on the surface-bearing area. Used for dewatering, product separation/evacuation, cleaning and removal of solids (such as wax);

Silicon carbide - medium- or high-density foam, coating on the surface-bearing area with silicon carbide/aluminium oxide grit or straps. Used for scraping or cracking hard deposits such as oxides or carbonates (normally for short runs);

Wire-brush - medium- or high-density foam. Coating on surface can be incorporated with either criss-cross pattern or total coverage of the surface-bearing area. Used for maximum scraping of materials such as scales (e.g. mill scale, etc.).

ADVANTAGES OF THE POLLY PIG

There are many reasons why polly pigs should be considered when developing a pigging programme. First, they can perform many of the same operations as other conventional pigs, while offering some advantages that can give the pipeline operator more control over what is to be accomplished inside the pipe. This is important when one considers that it is nearly impossible accurately to predict the internal condition of a pipeline that is not routinely pigged.

Safety - Polly pigs reduce the possibility of damage to the pipe. If for some reason a steel mandrel pig breaks apart, or if there is a cup or disc failure, the operator may be faced with an unwanted piece of unprotected steel lying somewhere in the system. Running another pig to remove the pig parts may result in damage to valves and other fittings. If there is any evidence that an obstruction possibly exists inside a line, then a foam pig should be run before a pig with metal parts is used. They are acceptable for use both in lined and non-ferrous pipe.

Flexibility - The compressibility of the polly pig allows it to negotiate short-radius bends, reducing valves, dented pipe and other pipe size reductions. Most medium-density foam pigs can take a 35% reduction in cross-sectional area. This means that a 20-in polly pig could conform to 16-in pipe, and a 36-in pig could conform to 30-in pipe. The special urethane foam has physical characteristics known as memory and resilience, which allow it to return to its original shape and diameter once it has passed through a reduction.

Custom designs - Because an operator sometimes faces unique pigging situations, he has the occasional requirement for a pig that is not available "off the shelf". Due to the method of moulding foam and applying external coverings, it is relatively simple to design and build a polly pig for a particular pipeline problem.

Less risk of a "stuck" pig - with the flexibility offered by the polly pig, there is less risk that it will get stuck at a dent, partially-closed valve, or some other unknown obstruction. A foam pig can easily deform to accommodate diameter reductions, and in the event that it does get lodged in the line, it will have a tendency to break apart if sufficient differential pressure is applied.

Cleaning ability - an efficient cleaning pig serves two functions while inside a pipeline. First is the scraping or wiping of the pipe surface; the second is to assist in moving the deposits out of the pipeline. There is more surface-bearing area on a foam pig than on any other standard-sized, conventional design. For instance, in a 24-in pipeline, a polly pig has three times more surface in contact with the pipe wall than a four-cup mandrel pig, and seven times that of a sphere. The foam pig has a jetting-type by-pass between the surface-bearing area and the pipe wall to assist in suspending deposits such as scale or wax ahead of the pig. This reduces the risk of solids piling up in front of the pig and possibly causing the pig to get stuck.

Removal of solids from a pipeline always involves a certain level of risk. If the solids pile up ahead of the pig, they can form a plug and possibly cause the pig to stop moving. One concept, or method, available to the operator faced with cleaning a severely-fouled pipeline, is the "progressive pigging" procedure utilizing foam pigs. If a pipeline has accumulated a large volume of deposits such as paraffin or scale, it can be difficult, and sometimes disastrous, when an attempt is made to remove too much of the material during any given pig run. Using polly pigs, an operator can take advantage of the density ranges, various designs and diameter sizes to safely remove the solids in stages. Soft, undersized pigs are initially run through the line to remove any loose, or soft, deposits, followed by progressively larger, firmer, and more aggressive pigs. The natural by-pass between the cleaner and the pipe wall helps to keep the solids in suspension ahead of the pig. This procedure gives the operator more control over what is taking place inside the pipeline, and reduces the risk of bridging the flow. Since it is difficult to accurately predict the build-up throughout the piping system, the flexibility of the foam pig allows for a degree of error if the deposit is heavier than predicted.

SUMMARY

Each pig design has unique characteristics that make it the pig of choice for a particular pipeline problem, but no pig design is suitable for every application. When a pipeline operator prepares for a pigging project, he must consider the design restrictions of his system, define the type of results he expects the pig to accomplish, and calculate the risks he will be facing. It is to his advantage to have a "tool box" full of different pig designs so that he may have several options in the choice for the proper pig to accomplish the job efficiently and safely.

The polly pig offers the pipeline operator the widest choice of designs to deal with the majority of pipeline pigging problems he will encounter. Flexibility, the pig's built-in safety factor, allows it to negotiate short-radius bends, pipe diameter reductions, and other pigging hazards that might cause other designs of conventional pigs to become plugged in a line. In short, the polly pig, with its wide range of possible configurations, is the most versatile pig available to the pipeline operator today.

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PIGGING AND CHEMICAL TREATMENT OF PIPELINES

THE PRIMARY purposes of any pipeline-maintenance programme are to maximize flow ability and prolong the life of the piping system. The two most common procedures for internal maintenance are chemical treatment and mechanical cleaning using pigs. Although the procedures differ in nature and effect, they are often used together to offer an efficient and cost-effective approach to controlling significant pipeline problems. An understanding of how each method works will give a clearer picture of how to combine the two for a more effective, comprehensive pipeline-maintenance programme.

INTRODUCTION

Chemicals used in treating oil and gas pipelines, such as pour-point depressants, flow improvers, corrosion inhibitors, biocides, and gas hydrate prevention products, are often applied using pigs to enhance their performance and efficiency, and to supplement their action.

Pigs are used to remove paraffin deposits, apply corrosion inhibitors, clean deposits from the line, and keep out accumulations of water. Water is the source of several problems in oil and gas pipelines, in that it allows corrosion to occur and bacteria to grow. Bacteria generate hydrogen sulphide, cause corrosion, and produce plugging slimes and solids in the fluids. Of equal value is the ability to remove sand, chalk, rust and scale deposits from inside the pipeline, which can cause under-deposit corrosion, a major form of accelerated corrosion, similar to pitting.

The following sections of this paper review the use of pigs in applying the chemicals used to treat pipelines, with an explanation of the purpose of the chemicals and how application by pigging enhances the performance of the total system.

PARAFFIN TREATMENT

Paraffin treating compounds are used for three main reasons:

- (1) to reduce the viscosity of an oil as it cools while traversing a pipeline, so that if flow in the line is stopped and it cools to ambient temperature, flow can be re-started within the burst strength of the pipe;
- (2) to minimize paraffin deposition on the walls of the pipe; and
- (3) to minimize plugging of instrumentation and metering equipment.

High-viscosity oil is difficult to pump, and can cause a major problem if a line is shut down and cools off. Deposit formation reduces the effective diameter of the line with an increase in pressure drop and a corresponding reduction in line capacity.

Two types of paraffin treating compounds are used in pipelines: crystal modifiers and dispersants. Crystal modifiers function by distorting the growth and shape of paraffin crystals. The result is that when a waxy oil cools below its cloud point, the paraffin precipitates as small, rounded, particles rather than acicular (needle-like) crystals. Needle-shaped crystals can interlock and form gels, greatly increasing the viscosity of the oil. Crystal modifiers change the paraffin crystal shape and surface energy, making it less likely to attach to the walls of the pipe, and to other wax crystals. Also, the crystal size remains so small that the crystals are less prone to sedimentation and agglomeration. For this reason, crystal modifiers are known as pour-point depressants or flow improvers.

Dispersants are surfactant compounds which alter the surface energy of paraffin crystals, making them less attractive to each other. Dispersants function by changing the interfacial energy between the paraffin crystal and the solvent oil, which also make the crystals less likely to deposit on solid surfaces such as pipe walls. This leaves them dispersed in the oil solvent in a non-agglomerated form. Both crystal modification and dispersion cause a reduction in the rate of paraffin fouling on the walls of pipes. Typical use rates for both paraffin compounds are in the range of 100 to 200 parts per million.

Crystal modifiers must be continuously added at a temperature above the "cloud point" of the oil to be effective. The cloud point of the oil is that temperature at which the oil becomes "cloudy" due to precipitation of paraffin crystals, and as such represents the solubility limit of paraffin in the oil. It is not the same as the "pour point" of the oil, which is the temperature at which the oil no longer pours out of a beaker under standard conditions. Oil below the pour point is still pumpable.

Low flow conditions, with more complete cooling, cause greater paraffin deposition. Once deposited, however, paraffin will not redissolve when the oil is below the cloud point, or solubility limit of paraffin in the oil. It must be removed either by solvent-dispersant chemicals, or mechanical or thermal methods. Generally, the solubility of paraffin in paraffin "solvents" is only a few percent, and mechanical methods are preferred. Putting "hot oil" into a line can dissolve paraffin deposits, but these are likely to re-deposit further down the line as the oil cools, merely transferring the problem downstream.

Paraffin control using pigs

Pigs are routinely used to control paraffin formation on pipe surfaces. There are many different pig designs used by the industry, such as *Polly Pigs*, spheres, and mandrel pigs equipped with cups (scraper, conical), discs or a combination of both. The function of any pig in this application is twofold; to scrape the adhered wax from the pipe wall and to remove the deposits out of the pipeline.

The interaction of a pig's surface bearing area against the pipe wall causes a shearing or scraping effect. By-pass around the pig assists in suspending debris in the oil in front of a pig to help carry it out of the line. The ability of a pig to remove wax is not necessarily its tight sealing capability (as in a batching operation) as much as it is its cutting, scraping or pushing characteristics.

Combined pigging and chemical treatment

Theoretically, either a chemical-treatment programme or pigging alone should be adequate in controlling paraffin formation. But in actual pipeline operating conditions, neither method can offer a complete guarantee. This is especially true in pipelines that carry oil with high cloud points, low flow velocities, and high paraffinic or asphaltenic characteristics. The rate of build-up can be so aggressive that the amount of chemicals necessary are cost prohibitive, and some paraffins exist which are difficult to fully treat. As well, the rate of deposition can be so rapid that pig runs are not run frequently enough to keep up with growth. Hard wax deposits can be removed by pigs equipped with wire brushes, scraping discs and other cleaning devices.

A better paraffin-control programme combines pigging with chemical treatment, as neither treatment alone is likely to provide all the benefits of a combination programme. The principles followed in paraffin-control programmes are:

Pipeline Pigging Technology

1. paraffin deposition rates are greatest when chemicals are not used;
2. the cost for complete chemical inhibition of paraffins can be very high;
3. allowing any pipeline or its instrumentation and metering systems to become fouled with significant wax deposits is both unnecessary and can lead to erroneous metering, possible loss of control of the line, and greatly-increased pumping requirements.

Pigs should be run periodically to scrape off accumulated paraffin deposits on the walls of the pipe which the chemical programme has not been able to prevent. This will also lead to reduced chemical consumption, as the goal is no longer complete prevention of deposits. Optimized programmes for paraffin control in pipelines combine chemical treatments with pigging to:

1. maintain the line in a clean condition and enable it to be re-started in a cold condition;
2. minimize the chances of sticking a pig, especially in offshore lines;
3. prevent flow capacity reductions or pressure drop increases through the line;
4. keep instrumentation and sampling equipment clean and in working order;
5. keep operating costs to a minimum.

When a pipeline has accumulated an excessive amount of paraffin build-up, either through improper or no maintenance at all, caution should be used in the design of the rehabilitation programme. When thick deposits are present, it may not be feasible or cost effective to use chemicals for dispersal of the wax, as very large volumes of the chemicals would be needed.

It can also be difficult and hazardous to try to move huge volumes of wax with pigs through long pipelines, as it is very easy to create a blockage and may require extraordinary pressures. Care must be taken to conservatively remove the wax in controllable amounts through use of progressive pigging techniques. Once pigs have removed all of the wax physically possible, chemicals should be used to treat the remaining paraffin.

As an example, a pigging programme to clean paraffin deposits was reported for a North Sea oil pipeline[1]. An estimated 7500brls of paraffin deposits had accumulated in the line over several years under low flow conditions due to cooling of the oil as it passed beneath the sea. A flow improver had been added to the oil to enable the line to be cold re-started in the event of a shut-down and cooling of the line. Whereas the chemical had undoubtedly reduced the rate of deposit formation, it had obviously not

prevented deposit formation. In addition, the pump pressure required to move fluids through the line was nearly five times greater than that required for a clean line.

Pigging was used to remove the paraffin deposits to prepare the line for a corrosion survey by an intelligent pig. A premium was placed on ensuring minimum risk to the line due to sticking a pig during removal of the paraffin deposits, as this would have shut down the field. A progressive pigging programme was developed to gradually remove deposits in a controlled manner. Foam pigs were selected, as they can easily deform to accommodate diameter restrictions. Further, with application of sufficient differential pressure, foam pigs will compress and by-pass major obstructions. Soft undersized foam pigs were used to start with, building up to harder and tougher pigs as the line was progressively cleaned. Once a series of foam pigs had been run, a pressure by-pass pig and several other mandrel pigs were used in the final cleaning process.

Once the line was cleaned, it was found that a paraffin-treating chemical was still required to prevent paraffins from clogging instrumentation and sampling ports. A final programme was developed in which periodic pigging was used in combination with chemical injection to maintain the line in good condition.

CORROSION CONTROL IN PIPELINES

Corrosion is the most serious problem associated with pipeline maintenance. There are enormous sums of money spent each year on prevention, monitoring, inspection and repair of corrosion-related damage. Most corrosion programmes are treated chemically with inhibitors, which are used to form a protective layer on the walls of the pipe by adhering to the metal or corrosion product layer such as iron carbonate or iron sulphide. Corrosion inhibitors come in several basic types, such as oil-soluble water-dispersible, water-soluble, limited-solubility (gunkers), and volatile, and each performs uniquely in different pipeline conditions. Inhibition can be applied in a batch procedure where the persistent nature of a heavy protective film may last for weeks or months. Or, inhibitors can be continuously injected into the pipeline in low concentrations through a continuous injection programme, where a thin film is gradually laid down and maintained over time. The chemicals work very well, provided that an effective film can be established through proper application.

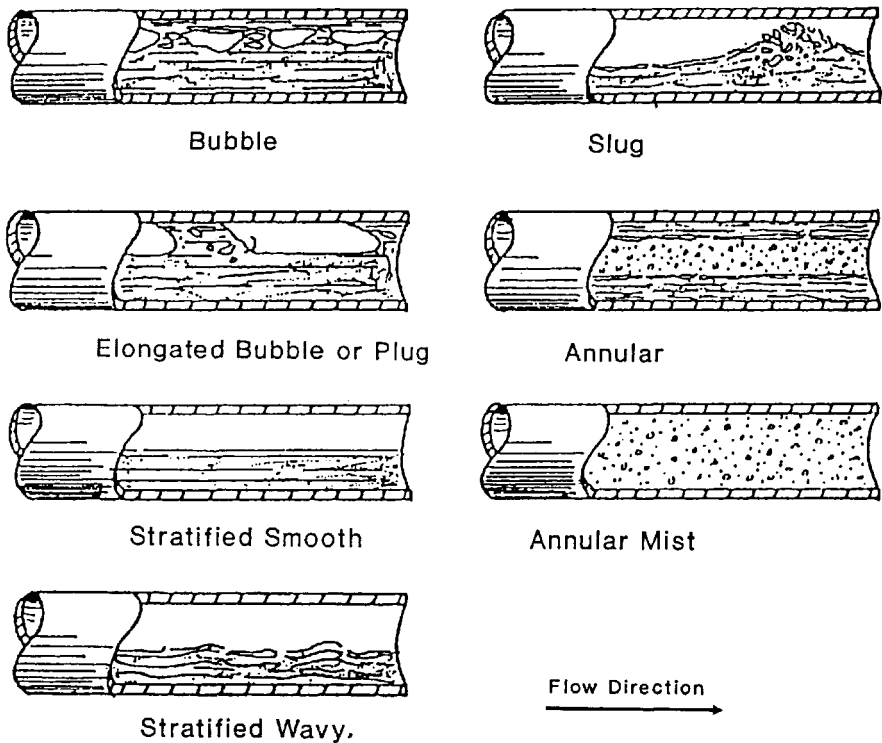


Fig.1. Various multi-phase flow regimes.

Corrosion inhibitor treatment of oil and gas pipelines

One problem area in treating gas pipelines is that stratification of liquids in the line may occur; therefore, the flow patterns or regimes must be considered when applying corrosion inhibition in gas lines. When multi-phase conditions exist, liquids will stratify along the bottom of the pipe, with water forming a separate layer beneath the hydrocarbon liquids. With these conditions, some types of corrosion inhibitor will not properly contact the upper walls of the pipe, leaving a good portion of the surface unprotected. Fig.1 shows the change in flow regime from stratified flow to slug flow when fluids start flowing uphill. Fig.2 indicates the change found from slug flow to stratified flow when fluids start moving down-hill. In a wet-gas environment,

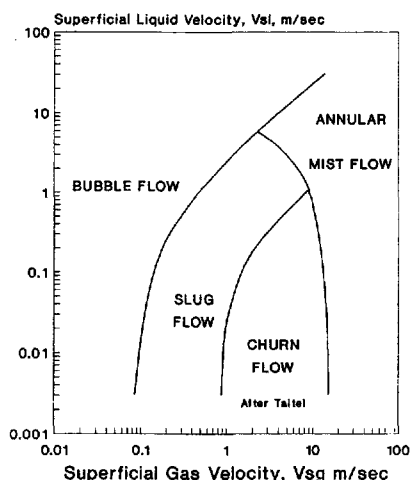
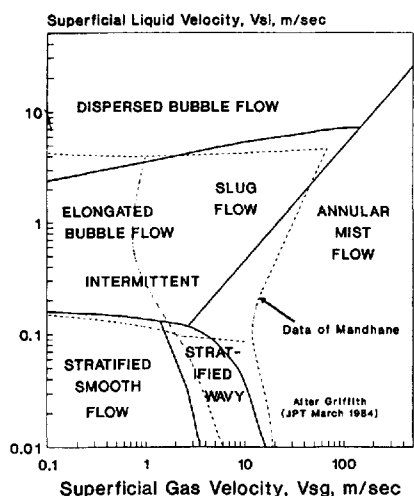


Fig. 2a (left). Horizontal multi-phase flow map.

Fig. 2b (right). Vertical multi-phase flow map.

condensation of water and hydrocarbons caused by cooling occurs over the entire internal surface of the pipe. Once the liquids condense, they fall to the bottom of the line and collect in low spots and up-hill inclined sections. Accumulation of liquids is known as “liquid hold-up”, and causes large increases in pressure drop through the line. It can also pose problems in corrosion inhibitor treatment because it is difficult to treat effectively both the liquids and the exposed pipe wall. Water is a source of several problems in oil and gas pipelines, in that it allows corrosion to occur and bacteria to grow. Frequent pigging is advised to keep accumulated water and other liquids to a minimum.

Corrosion inhibitors are cationic surfactant chemicals which chemically bond to any negatively-charged surface. Included in this grouping are metals, corrosion products such as iron carbonate, iron sulphide, and iron oxide, and sand and clay. If deposits of dirt, corrosion products, and bacteria are inside the pipe, they can both consume chemicals meant to treat the walls of the pipe, and prevent the chemicals from contacting the walls of the pipe beneath the deposits. For both of these reasons, pipelines should be as clean as possible when applying corrosion inhibitor. It is estimated that twice as much chemical is needed to protect a dirty line as a clean one. This cleaning is usually done by a pigging programme.

In oil pipelines, water can also stratify at the bottom of the line if the velocity is less than that required to entrain the water and sweep it through

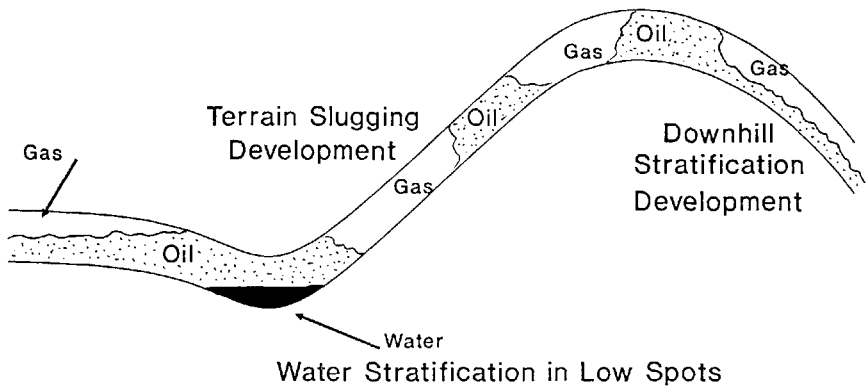


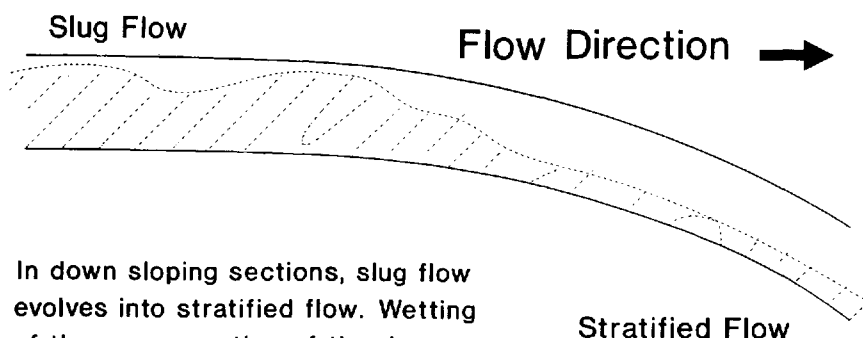
Fig.3. Up- and down-hill multi-phase flow; effects of inclination.

the pipeline system. Oil pipelines are best inhibited using oil-soluble water-dispersible filming amine-type corrosion inhibitors which can disperse sufficiently into stratified water layers to prevent corrosion beneath the water.

Inhibitor application with pigging

When inhibiting either gas or oil lines, pigs should first be used to sweep out water and remove any sediment from the pipe wall. If liquids alone are being displaced, a sealing pig would be sufficient. Cleaning pigs equipped with wire brushes or scraping discs should be used if deposits such as wax or scale are evident in the line. A film of inhibitor should then be applied using periodic batch treatment with sealing pigs. Batching keeps the chemical in a solid column ahead of the pig, as shown in Fig.3, allowing exposure to the entire pipe surface. If pigs are not used, the slug of chemical will lose its column form, leaving portions of the pipe unprotected. Batching, followed by a continuous low-concentration injection programme, is recommended over an injection programme alone, as there is no way to ensure that all of the pipe wall has been treated.

A Canadian sour gas-gathering system in which corrosion failure occurred is discussed in Refs 2 and 3. This system had been treated with a liquid-soluble corrosion inhibitor in a continuous injection programme. Stratification existed in sections of the line, especially down-sloping portions. The liquid-soluble inhibitor used provided excellent protection to the bottom of the line, but the top sections of the line were left unprotected. These lines burst after



In down sloping sections, slug flow evolves into stratified flow. Wetting of the upper section of the down sloping pipe by liquids is seldom achieved unless the system is pigged . Corrosion inhibitors must be run between pigs to be able to coat the upper portions of the pipe.

Fig.4. Downward-sloping multi-phase flow.

several years, due to corrosion of the upper portion of the pipe in down-sloping sections of the line. The operator changed the application of inhibitor to a batch method between pigs, to ensure that the complete surface of the pipe wall would be treated and protected against further corrosion.

BIOCIDE TREATMENT OF PIPELINES

Control of bacteria and bacterially-induced corrosion in pipelines is another area where application of the chemicals used is greatly enhanced when applied in conjunction with pigging. Anaerobic sulphate-reducing bacteria (SRB) and anaerobic acid-producing bacteria (APB), are two types of bacteria commonly found in oil and gas pipelines. SRBs produce hydrogen sulphide, while APBs generate acetic acid, both of which are highly corrosive.

Pipeline bacteria

Bacteria live in water, but prefer to grow on metal surfaces. Once bacteria establish as viable colonies on the pipe wall, they protect themselves with a

polysaccharide outer layer[8] which can effectively filter biocides and other chemicals. This protective layer can defeat routine bacteria control programmes based upon simply batching bactericides through the line.

Pigs used in conjunction with a biocide programme can be very effective. A pig should first be run to remove substantial build-up of water. Wire-brush pigs can be used to scrape and scratch the bacteria colony outer layer, and remove bulk bacteria growth from the pipe wall. This prepares the pipe surface for the application of biocides, enabling the biocide to reach and destroy the colony, and reducing the volume of bacteria to be treated. Nylon-bristle brushes are available for coated and plastic-lined pipe systems. Sealing pigs can then be utilized to batch a slug of biocides, enabling maximum exposure to the affected areas.

This approach has proven very successful in treating an 8-mile long, 12.75-in gas condensate pipeline which was infested with SRB. A programme was developed where a drum of biocides mixed with 50brls water was pumped into the line, followed by a pig to batch the liquid through the system. After several months of this programme, it was apparent from monitoring the pipeline that the bacteria were continuing to grow. A new procedure was adopted where a wire-brush pig polly pig was inserted into the line, 120brls of water containing biocide were pumped in, followed by a sealer pig. Since this procedure was adopted, no further evidence of microbiologically-induced corrosion was found.

SELECTION OF PIG DESIGN

As in any pigging application, the best results are achieved when using a pig design which is suitable for the required procedure. Using the wrong equipment when combining a pigging and chemical programme can waste expensive chemicals, leave pipe surfaces insufficiently clean, and in the long term actually contribute to pipe failure. For the applications discussed in this paper, cleaning pigs and/or sealing pigs should primarily be used.

Chemical treatment is most effective when applied to a clean pipe wall. For this reason, pipeline operators should ensure that aggressive cleaning pigs be run in lines that have the potential for wax or scale deposition. Although any type of pig offers some degree of cleaning, it is recommended that pigs with heavy-duty scraper cups, stiff guide discs, and/or wire brushes, be utilized when any deposits are expected. Well-established build-up such as hard scale, wax or colonies of bacteria, usually are left unaffected unless well "scratched" by the passage of a pig. Conical cups and spring-loaded blades are

somewhat more effective on very soft deposits, but are not very effective on sticky or hard waxes, as they have a tendency to “flex” and run over debris. Spring-loaded brushes will also flex, but they will cut into hard deposits much better than blades. It should also be noted that spheres are not cleaning tools, and can press deposits further against the pipe wall. *Polly Pigs* have some effect on paraffins and scale if they are made from high-density foam and have wire brushes or other scraping surfaces.

When moving large volumes of deposits through a long pipeline, care must be taken in not pushing so much debris that the pig becomes stuck. It is recommended that there be some amount of by-pass around the pig, to assist in suspending debris out in front of the pig and to help keep blades and brushes clean. All pigs have some degree of by-pass; however, it is possible to increase this amount by controlling the size of the pig’s sealing area or by providing by-pass ports through the pig.

Use of the progressive pigging technique allows large amounts of debris to be removed safely by removing a little at a time in a progressive manner. The technique utilizes foam pigs of different sizes, coatings, and densities to gradually remove deposits, rather than attempting to remove them all in one pass. Starting with soft, low-density, pigs, the condition of the line is assessed by examining the condition of the pig after passing through the line. By gradually increasing the density and diameter of the subsequent pigs, removal of deposits is controlled.

For removal of settled liquids or for batching chemicals, a good sealing pig should be used. There are many such designs available, such as *Polly Pigs*, spheres, cup or disc pigs. Conical cups are deemed to be very good for sealing, although any pig with four cups should be adequate. If a disc pig is used, it is recommended that the configuration is equipped with guide discs to help support the mandrel weight. This will reduce the potential of by-pass around the softer sealing discs. Spheres can be inflated so that a tight seal is realized; however, spheres offer the least amount of surface bearing area and minimal wiping ability of any pig. A criss-cross coated *Polly Pig* offers a good seal, but may not have as much usable life as offered by the other designs. When batching chemicals, it is advisable to use two pigs, one in front and one behind the slug of chemicals, to help contain the liquid in a full column form. This is very important when batching in a downhill slope. A brush pig can be used as the front pig to help prepare the pipe surface for the treatment.

In order for any pig to perform its task sufficiently, it must be in good operating condition. Parts such as cups, disc, springs, brushes, and blades should be routinely inspected for wear and fatigue. Replacement of these parts should be made when it is determined that they are no longer useful in sealing and cleaning, or in supporting the weight of the pig. Using a worn or

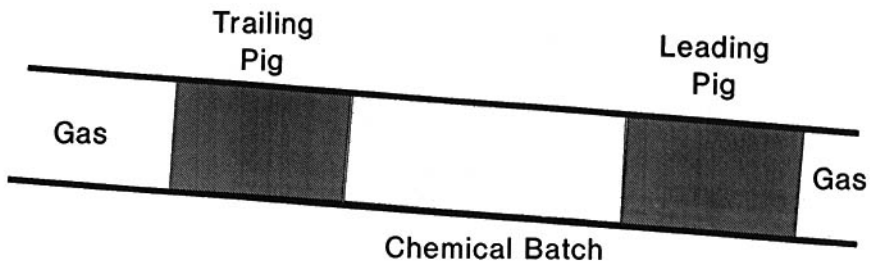


Fig.5. Batch between pigs.

inefficient pig is one of the more common and costly mistakes made in pipeline maintenance. Liquids and deposits can be left in the pipeline, although frequent pigging is performed. It is also possible to lose costly chemicals when batching, due to excess by-pass around worn sealing parts.

SUMMARY AND RECOMMENDATIONS

Both chemical treatment and mechanical pigging offer solutions to various pipeline operating problems; however, neither method alone is likely to provide the benefit of a combination programme. Chemicals are most effective and efficient when used primarily to treat problems at the pipe surface, such as the formation of wax deposits, bacteria colonies and corrosion. Pigs are best used to prepare the pipe surface for the application of chemicals, to help distribute the chemicals evenly throughout the pipeline, and to minimize the volume of chemicals needed by removing bulk deposits and entrapped fluids. If chemical treatment and pigging are combined in a well-developed preventive-maintenance programme, it is possible to keep corrosion damage to a minimum, maximize the operating efficiency of the pipeline, and reduce chemical treatment costs.

The following recommendations should be followed when developing a chemical treatment and pigging programme:

- (1) conduct a thorough analysis of the pipeline's operating conditions, identifying all possible flow, deposition or corrosion problems;

- (2) identify the best chemical for the situation, the most effective dosage and method of application;
- (3) start with a clean pipeline. Remove unwanted liquids, scales, and wax deposits with the appropriate types of pig;
- (4) whenever possible, apply chemicals in periodic batch treatments using pigs;
- (5) establish a well-defined maintenance programme, using low-concentration chemical injection between batching, and frequent pigging;
- (6) select pig designs that are well suited for the application, and keep the wear parts in good, usable condition.

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SPECIALIST PIGGING TECHNIQUES

INTRODUCTION

Whilst the majority of operational pipelines can be successfully pigged using standard proprietary products, there are occasions where a specialist "one-off" type of pig is required. Due to the individual nature of such pigs, it is usually not reasonable to expect the manufacturers of standard pigs to produce them, and in any case they often do not have the necessary operational experience to design such a specialist pig.

In 1979 McAlpine Kershaw was established for the specific purpose of designing and producing specialist pigs to cope with unusual and difficult circumstances. Our initial thoughts were to produce a range of various specialist pigs, but we quickly learnt that it was better to wait for a pipeline operator to approach us with a specific problem and then to design and develop a pig to solve the problem.

During the 11 years of our existence we have designed and developed many specialist pigs to solve specific problems, which are described in this paper.

SPECIALIST PIGS

Multi-diameter pig

This was the first development project which we undertook on behalf of a client in the Middle East, who required to clean a water-injection ring main having diameters of pipe ranging from 20in to 26in. At the time this project was undertaken, there were no other suitable multi-diameter pigs on the market. Our own multi-diameter pig is based on a different principle of

construction from that of standard manufacturers, in that we utilize a steel body fitted with over-size polyurethane butterfly discs together with overlapping thin spring steel plates. These plates protect the butterfly discs from abrasion, assist with the cleaning operation, and give added support to the pig whilst it is in the pipeline.

Pressure by-pass pig

One of the most notable new pig designs to emerge in recent years is the pressure by-pass pig produced by ourselves. It was specifically developed for pre on-line inspection pigging, and is now used for both proving and cleaning operations. The front of the pig is fitted with what is effectively a pressure-relief valve, having a diameter of around 40% of the internal bore of the pipeline and set to open at a pre-chosen differential pressure. If, during a proving or cleaning run, the pig builds up a large accumulation or slug of debris ahead of it, the differential pressure across the pig will obviously rise as the pig begins to work harder. If a conventional cleaning pig was being used, the accumulation of debris ahead of it might well increase until the pig became stuck or substantially damaged. This cannot happen with a pressure by-pass pig, since once the pre-set differential pressure is reached, the by-pass valve opens, thereby allowing a substantial volume of fluid or gas to flow through the pig body. This results in the debris being jetted or blown away from the front of the pig, after which time the differential required to run the pig will drop, the by-pass valve will close, and the pig will move on. This sequence may take place many hundreds of times during a run in a particularly-dirty pipeline before the pig reaches the receiver. Also, it is most unlikely that the by-pass pig can ever block the pipeline in the event that it becomes totally stuck, since the by-pass facility allows continuous by-pass of the propelling medium. To date we have designed and supplied many by-pass pigs, ranging in size from 6in to 42in diameter.

Magnetic cleaning pig

Whilst the presence of ferrous debris, such as welding rods and the like, does not generally present a major problem in an operational pipeline, it is essential that such debris is removed if on-line inspection is to take place. Most major pig manufacturers offer magnetic cleaning pigs, which are generally standard swabbing pigs with permanent magnets attached. Under normal circumstances such pigs might be adequate and will generally remove the debris during several runs through the pipeline. However, if the presence of

ferrous debris is particularly high, then a more aggressive approach is required so that the debris can be removed more efficiently and therefore more quickly. We are aware of one pipeline which was so heavily contaminated with ferrous debris that the pipeline operator carried out a total of 43 separate pigging runs using a standard magnetic cleaning pig before all debris was finally removed from the pipeline. A specialist pig would have reduced the number of runs considerably.

Following investigation and exhaustive trials of the various types of magnet available, our first improvement has been to mount and orientate the magnets for maximum efficiency and performance. The second major improvement is the option of the addition of magnetic brushes which closely resemble the brushes of an on-line inspection pig (working on the magnetic flux leakage principle). The advantage of using magnetic brushes is that they can be arranged in close proximity to, or even touching, the inside wall of the pipe, due to their ability to flex when traversing bends or other restrictions. Permanent magnets, on the other hand, have to be at least 3in away from the pipe wall to avoid the pig fouling or becoming stuck in a bend. We have also found that for optimum magnetic cleaning it is better to run a twin-module pig, comprising separate bodies coupled together using a universal joint. In some situations we will add a third body if circumstances demand it.

It is recommended that pipeline operators carry out a magnetic cleaning programme well in advance of any form of on-line inspection operation, as it is never known how much magnetic debris is present in a particular pipeline until magnetic cleaning operations have commenced. If, for instance, it is planned to carry out on-line inspection in perhaps one to two years time, then it would not be too soon to commence magnetic cleaning immediately, since once the line has been successfully cleaned, further contamination is not likely to take place since ferrous debris is generally the result of construction operations. An early magnetic cleaning programme will ensure that adequate time is available to complete the operation efficiently.

Pin-wheel pig

This revolutionary pig has been specifically designed and developed for the removal of hard wax and scale adhering to the inside wall of the pipe which conventional cleaning pigs cannot dislodge. Although this wax or scale is usually at its worst in the 4 to 8 o'clock position, the pin-wheel pig, through its cleaning assembly, will give a 360° circumferential cleaning action, and also allow for any rotation of the pig. The cleaning assemblies consist of a number of heavy-duty polyurethane discs (referred to as pin-wheel discs) which are up to 2in thick and have an outside diameter in the order of 3-4in

less than the inside diameter of the pipeline. Protruding radially from the circumferential edge of each disc are a number of steel pins which are screwed into threaded housings anchored into the disc. The length of the pins is such that the diameter across any two opposite pins is greater than the inside diameter of the pipeline by up to 1in, depending on line size. This means that when the disc is travelling through the pipeline the pins are bent back at a slight angle, which both assists in the cleaning action and also compensates for any wear. The pins have hardened inserts to reduce wear to a minimum and the inserts are radiused to prevent damage to the pipe wall.

Depending on the size of pipeline, four or six pin-wheel discs are attached to a purpose-built steel body using appropriate retaining bolts. The pin-wheel pig is always towed behind a conventional swabbing pig using a universal joint to couple both pigs together. Each pin-wheel disc is orientated to ensure that the cleaning pins on each disc are suitably offset from one another; this offset ensures that the total surface area of the pipeline is cleaned. The use of removable pins enables many options for wax/scale removal and cleaning to be adopted, and on completion of each run any worn or damaged pins can be simply replaced with new ones. By increasing the hardness of the polyurethane discs and/or the length of the cleaning pins, increased aggressiveness is achieved.

We always recommend a progressive approach when cleaning a pipeline using the pin-wheel pig, in order to reduce the risk of a blockage which can occur when too much material is removed from the pipe wall. It is preferred that during the initial cleaning runs less than the entire internal surface of the pipe will be cleaned, as it is better to remove wax or scale from the pipe wall progressively during a number of pigging runs rather than trying to remove it all during one run. This is achieved by running the pig with some of the pins removed for initial runs, and then fitting more pins for each subsequent run until all the pins are fitted. The design of the pin-wheel pig is such that little or none of the wax or scale removed from the pipe wall will actually be pushed forward by the pig itself; it will be left behind in the line. For actual removal of this loosened wax or scale from the pipeline we use the pressure by-pass pig.

Brush pig

This pig was developed for a client operating aviation spirit pipelines where cleanliness is extremely important. The pipelines were being cleaned using standard articulated pigs carrying steel wire brushes which were relatively successful in removing larger dirt particles. However attempts to improve the cleaning action by utilizing stiffer brushes merely removed the

protection of the corrosion inhibitor from the pipe wall, which was unacceptable. We designed and produced a unique brush pig using nylon brushes impregnated with carborundum grit. During trials, it was found that the brush pig was extremely efficient in removing very fine debris from the pipeline, thereby considerably increasing the times between filter changes at the airfield due to the increased cleanliness of the product.

Due to superior cleaning ability, far in excess of a conventional cleaning pig, we now use the brush pig in our service operations for clients requiring as clean a pipeline as it is possible to achieve. However, due to the efficiency, we generally adopt a progressive cleaning approach, starting off with conventional cleaning pigs and only using the brush pig for final cleaning once the majority of debris has been removed from the pipeline.

Shunting pig

This pig is basically a three-section articulated pig which has been specifically developed for the removal of stuck or lost pigs from pipelines. Our experience has taught us that if a pig does become stuck or lost in the pipeline there is little point in running a second pig of similar or identical design, since this pig is likely to succumb to the same problem as the first pig and also become stuck or lost itself. What generally happens to a pig which is required to push a stuck or lost pig (usually in pieces) is that the additional effort of removing the debris causes the second pig to become damaged itself. Using a three-section articulated pig, we recognize that the first section will probably become damaged to a considerable extent as it pushes the debris ahead of it, but drive will be maintained because of the second and third sections which never come in contact with the debris being pushed out. Additionally, the shunting pig is deliberately made to be extremely heavy to give increased momentum, since lightweight pigs are of little or no use in removing stuck or lost pigs from pipelines. Much attention is paid to the design of a shunting pig so that there is no metal-to-metal contact between the shunting pig and the debris being pushed out, and this is achieved by fitting a hard polyurethane bumper ahead of both the pig body and the front cup. The shunting pig is also equipped with permanent magnets for tracking purposes, together with a battery-operated electro-magnetic device for positive location when stationary.

A further use for the shunting pig is in pipelines which are particularly hostile to pigs, thereby requiring a much stronger construction of pig. The extended length and increased number of cups and discs substantially improves its performance in difficult conditions.

“Easy loading” pig

This pig has been developed by our sister company ITAC specifically for offshore use during the final tie-in between a subsea pipeline and the platform riser. Prior to the tie-in being carried out, the pipeline itself will have been successfully pigged and gauged, as will the riser. Once the two are tied-in, it is generally necessary to run a final gauging pig so that the tie-in spool will also have been gauged. As it is virtually impossible to back-load a cupped or bi-directional gauging pig into the open end of a subsea pipeline prior to tying-in, it is usually necessary to run a gauging pig from the very start of the pipeline through to the platform to gauge the tie-in spool. This is costly and time-consuming, since the only relevant piece of pipe which needs to be gauged is that of the short tie-in spool between the pipeline and the riser.

The “easy loading” pig is effectively a bi-directional pig using split discs which initially are undersized to the pipeline bore. This allows it to be easily inserted into the open end of the pipeline prior to the tie-in operations by a diver. Once inserted, the discs are increased in size to form a tight seal with the pipe wall by activating a spring mechanism within the pig body. Following tie-in operations, the “easy loading” pig is then run through the tie-in spool piece, up the riser and into the pig trap on the platform. This obviously saves tremendous amounts of time and money, and especially so where the pipeline is of considerable length.

SUMMARY

The art of pigging an operational pipeline is not an exact science, especially in respect of pipelines which do not conform to normal parameters. It is hoped that this paper will give pipeline operators food for thought, and to let them know that help can be on hand in situations where conventional pigs are not appropriate. It is fair to say that nothing is impossible, providing time, effort, expertise and money are available to solve the problem.

PIPELINE GEL TECHNOLOGY: APPLICATIONS FOR COMMISSIONING AND PRODUCTION

PIPELINE gels have been developed and utilized for numerous applications where a pipeline has been required to be cleaned to a high specification, either during initial commissioning or as part of a continuing maintenance programme.

The original concepts of gel cleaning allowed lines to be cleaned where potentially large volumes of debris in the line may well have caused a pipeline pig to become stuck. This technique has actually enabled long pipelines to be cleaned in a single operation. These tasks have been undertaken cost effectively, meeting the cleanliness standards specified.

Gel systems have many more applications and are used both in conjunction with mechanical pipeline pigs, and also with other viscous polymer gel pigs. Simply by changing the characteristics of the gel it is possible to change their suitability for a large number of different applications in widely varying environments.

INTRODUCTION TO GEL TECHNOLOGY

Nowasco has developed significant operational experience in gels which have been designed for use in very different pipeline operations. These versatile fluids perform many of the functions of a conventional mechanical pig and have the following characteristics:

1. they maintain a good seal over long lengths of pipeline;
2. the gels are capable of passing through lines of changing diameter;
3. they pass through partial obstructions in the line without becoming stuck, and therefore can be used to locate obstructions in the line using pressure build-up calculations;

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4. the gels can support a large volume of debris, without plugging or sticking or depositing their load in dynamic or static environments;
5. all of the gels can be chemically altered to affect the viscosity and adhesive nature of the pig for any particular application.

Gelled fluids can be pumped through any line capable of accepting liquids and can be used in conjunction with mechanical pigs to improve their performance. Typical gelled fluid applications can be briefly summarized as follows:

1. *Cleaning debris from the pipeline*: Where long pipelines are required to be commissioned, and debris build-up ahead of the cleaning pigs is considered to be a problem, gels can be used to suspend and distribute the accumulated debris along the body of the cleaning train, allowing large volumes of material to be suspended and removed from the line in a single run. In the past one has often had to rely upon a large number of pig runs, usually in combination with high-velocity flushing, requiring, in many cases, high-horsepower pumping capability to overcome friction and ensure particle suspension.

2. *Dewatering the pipeline*: Gel pigs are also used to assist in the removal of water from the walls of a pipeline and can be manufactured to be compatible with, and be able to contain methanol or IPA between either high-viscosity polymer pigs or mechanical pigs. It has been found that certain types of gels are affected by these chemicals and care has to be taken in their selection; therefore full laboratory compatibility between the dewatering components and the product is recommended.

Nowasco also usually proposes running a dewatering fluid and a hydrocarbon gel to leave the hydrocarbon pipeline oil-wet; the hydrocarbon gel can be altered to lay down an inhibitor coat if required at the same time.

3. *Acting as product-separation pigs*: Gel can be used when two fluids are to be kept apart, e.g. water and oil. Here a viscous gel pig is placed in the line between the product. The gel system can be readily diverted on arrival and the lack of a mechanical pig may be preferred in a production line. The type of gel and length of gel plug are specifically designed for a particular operation depending on:

- (a) type of fluid to be separated;
- (b) temperatures to be found in the line;

Gels for commissioning and production

- (c) maximum line diameter and any changes in diameter;
- (d) optimum displacement velocity.

4. *Displacing condensate from lines:* Condensate, and other liquids can be removed from the system by the introduction of gel pigs into the line, which at the same time can be designed to lay down inhibitors, etc., on the pipe wall. The efficiency of the laydown can be controlled by using a mechanical pig which is slightly undersized to sweep the gel forward.

5. *Increasing the sealing efficiency of mechanical pigs:* Sealing mechanical pigs can minimize fluid by-pass and therefore reduce pig wear. By using a gel with a mechanical pig, pig wear can be reduced as the gels can be designed to lubricate the pipe wall, which may be of particular importance for long gas lines.

6. *Aiding in the removal of stuck mechanical pigs:* As mechanical pigs travel down a line, wear on the cups can increase the by-pass of the drive fluid. Movement will stop when there is a lack of differential pressure across the pig, or when any debris ahead of the pig causes the pig to stop. Conventionally, another pig is launched to remove the first, but due to the wear or debris build-up this may also become stuck.

A gel pig pumped down the line which, depending on the situation, can create a high differential pressure, would be more than sufficient to move a stuck pig. If debris build-up has occurred, some of the gel will by-pass the pig and entrain the debris which will allow the pig to move forward.

7. *Laying down coatings on the pipe wall:* Where specifically required, inhibitors, solvents and chemicals can be laid evenly down on the pipe wall to protect the system. This can be undertaken at the beginning of the operational life, or during it, using gel systems which are compatible with the line product.

8. *De-oiling multi-diameter pipelines:* In subsea applications, and other situations where multi-diameter pipelines occur in a system, gels have been successfully used to separate solvents and to de-oil and remove hydrocarbons from the pipeline wall, allowing high-quality water injection to be undertaken through the system. In these cases a simple gel train has been used and gel pigs separate the fluids. It should be noted that the actual gel pigs which are built for these jobs are built to be compatible with the fluids used in the system.

TYPES OF GEL

Three main types of gel pigs are commonly used for pipeline applications:

High-viscosity sealing gels

Sealant gels are based on the series of gels designed for downhole fracturing techniques. These gels are visco-elastic and self-healing, with a strong cohesive attraction, and are typically used in situations where contamination of the product or pipe wall is not important.

Commissioning cleaning gel systems

Cleaning gel pigs are prepared from fresh water or seawater gelled with a biodegradable polymer. The gel has visco-elastic and plastic flow properties (pronounced yield-point and significant cohesive behaviour). The gels have a high yield strength which ensures that the debris remains suspended even if the gel is static for long periods.

Debris pick-up mechanism: Debris pick-up gels are usually and most successfully run in conjunction with a following mechanical pig, displaced at between 1 and 3 ft/sec to ensure that the gel is in plug flow during the pipeline transit. In this flow regime, the core volume of gel moves as a semi-solid plug at higher displacement velocity than gel on the wall; therefore there is little exchange with the material, with the almost-stationary gel near the pipe wall. During displacement the gel in this annular zone is removed from the pipe wall by the mechanical pig, and flows forward into the core zone, forming a 'convection system'.

The gel is very adhesive to either previously loose or newly pig-loosened debris. This debris is entrained and carried forward into the core by the action of the following pig. In this system, debris cannot accumulate in front of the pig causing it to stick, but is distributed evenly throughout the gel body.

As some of the debris pick-up gels are readily water-dispersible, and if pig reliability is doubtful or a situation exists where mechanical pigs cannot be used due to diameter changes, or launching/landing difficulties, and polymer pigs are used, then the cleaning gel can be protected front and rear by a sealant preventing dilution by entrained and by-passing water. Because of their very different characteristics, gel and sealant gels do not readily inter-mix.

Gels for commissioning and production

It should be noted at this time that there are two types of gel pig system used. The first type is used always in conjunction with a mechanical pig to prevent by-pass of displacing fluid; these have a lower viscosity than the second type of polymer gels which are premoulded and have a very high viscosity and can actually be used as a mechanical pig.

Train design: The amount of cleaning gel required is primarily dependent on the maximum amount of debris expected. In new pipelines, this is usually estimated at 0.05 kg/m² of pipe wall (assuming the line has been gauged before). Using 4li of gel per kilogram of debris there is a more than adequate margin for such contingencies as gel dilution, or more debris than expected. A typical gel pig will tolerate 100% dilution and still carry the total expected debris. Undiluted, it will carry several times this amount of debris with only a limited increase in flow resistance.

Rinsability of gels: Following investigations into the success of the early gel treatments it became apparent that gels were capable of supporting large amounts of debris. It was, however, assumed that all of the removable debris had been carried from the line by the gel. It was only at a later date, when subsequent flushing and pigging removed further debris from the line, that the efficiency of the chosen gel system was questioned.

Nowasco began an extensive research programme into the gel systems that had been used on the operations. It was found that a thin layer of gel remained trapped on the pipewall and that the subsequent pig did not remove all of the gel. The gel layer left behind was found to vary from 1mm to 0.1mm in thickness. This layer effect was more noticeable when the gels were not displaced by a pig and much larger volumes of gel were left behind. Subsequent flushing of the line did not remove the gel, and it was found that:

1. remaining gel would become loose and entrain itself into the product if not fully removed prior to the introduction of the product;
2. debris with a conventional gel train design may be trapped below this film and remain in the line;
3. any remaining gel would have an adverse effect on the efficiency of the drying process.

Nowasco has developed RPG (rinsable pipeline gel) as an alternative to the existing gels in certain applications. This gel is fully rinsable but does not break down on contact with water. It is, though, slowly diluted and its suspension ability decreases with dilution. RPG is designed to be able to hold its full debris load after 100% dilution by water has occurred.

This trade-off between suspension and rinsability required the use of proven high-sealant pigs and, in most cases, a modified design of the gel train. The gel which was used for cleaning the Fulmar line in the North Sea (290km, 20in) to a cleanliness level of 10 microns proved that :

1. RPG was fully rinsable and no residue was left at the pipe wall;
2. no effect on the drying period occurred;
3. subsequent pig runs found no debris in the line;
4. the gel did not trap debris against the pipe wall.

Hydrocarbon gels

Gelled hydrocarbons, such as diesel, kerosene or, in many cases, line product, can be mixed as the base fluid, giving the high sealing efficiency characteristic of gel pigs. They are used in operational oil or gas pipelines where aqueous systems are unacceptable, either run alone if displaced by liquids, or usually with a mechanical pig when displaced by gas.

In gas pipelines, continuous injection of corrosion inhibitor may need to be supplemented with a periodic slug treatment. Sticky diesel gels can be loaded with up to 20% of an inhibitor, and when injected ahead of a routine mechanical pig run, give a satisfactory laydown on the whole pipe circumference throughout its length, with internal flow within the pig allowing continuous migration of fresh inhibitor to the pipe wall. When injected into the line, the gel spreads along the pipe base, until launching of the mechanical pig bulldozes it into a diameter-filling 'gelly pig'. Gas transmission continues during gel injection, although the peak rate may have to be temporarily reduced.

An important additional benefit, if not the joint objective, of a diesel gel run is that it will flush out condensate, or water that has dropped out and accumulated in the line. In a wet or rich-gas pipeline, especially if irregularly contoured, even frequent conventional pigging can by-pass considerable quantities of such liquids.

The gelling chemicals contain no organo-chlorines and will not poison refinery catalysts, and are disposed of either by flaring or by dilution of the gel by an acceptable hydrocarbon.

The sealant and cleaning gels are usually aqueous systems, prepared from fresh water or seawater, and are both biodegradable and have no adverse environmental effects when discharged at sea.

It should be stressed that all the gel systems are designed for a specific application and that close liaison between the engineers responsible for the

design of the gel and the customer is required to ensure that a suitable system is utilized.

POLYMER GEL PIG

In addition to the cleaning gel systems, Nowasco has developed a viscous water-soluble pre-moulded pig which is compressible and can be pumped through various diameters of pipework, and which has been used in place of conventional pigs as discussed earlier.

The polymer is precast in a steel canister for transportation and loading into the pig launcher; should the client wish it can be colour coded for ease of identification.

Nowasco has found that these types of pigs have to be selectively used, and that in long gas lines breakthrough of gas and destruction of the pig may occur. They do, however, have applications where outlet restrictions are small as the pigs can be broken up under pressure and discharged through small-diameter outlets.

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PIG-INTO-PLACE PLUGS AND SLUGS

INTRODUCTION

Following the Piper Alpha tragedy in the North Sea, and other accidents around the world in the last few years, a large number of operators and legislative bodies are beginning to require that emergency isolation systems are available on the appropriate pipelines, enabling the systems to be safely shut down in an emergency. There are many pipeline systems throughout the world which cannot be fully isolated should there be a problem at a particular point within the transmission system.

The purpose of this paper is to describe a number of techniques which are being successfully used, as well as ones presently under development, to enable the pipeline to be isolated without requiring the complete system to be decommissioned. Obviously, there is a significant cost advantage in working on a line while it is still full of product, as long as this can be undertaken safely and quickly. The alternative option would be to drain the line of product and either flood the system or free the line of gas prior to starting work. Either option can have not only economic effects in the local region, but also affect the complete distribution network.

In 1988 it was recognized that there may well be an application for a subsea intervention system which would enable additional pipelines to be tied into a main trunk line without decommissioning the complete pipeline. In a typical North Sea scenario, we may have a 200+km pipeline which has been dried at the time of commissioning down to the dewpoint of -20°C , and operated in a controlled manner since then. The time required to recommission the pipeline back to the acceptable standards for product delivery is such that after the installation of a spool piece into the pipeline and subsequent testing, a further 10-15 days may be required to dry the pipeline. It was for this initial intervention requirement that a number of isolation designs were selected for further evaluation. The systems evaluated and developed to operational status have the following in common:

1. they are capable of withstanding a significant differential pressure;
2. the system has to be reliable and repeatable, with fail-safe systems to prevent failure;
3. the barrier system has to be easily introduced into the pipeline;
4. the barrier system should not cause any damage either to the pipe wall or to the integrity of the pipeline system;
5. the system has to be easily removable following completion of the work.

GEL ISOLATION

Through its downhole applications, Nowsco has developed a cross-linked aqueous-based gelling system which has been used for temporary abandonment of well bores. The properties of this particular gel are well known, and in practice lengths of gel 150-200ft long placed inside 7-in internal diameter pipe have been able to withstand in excess of 250psi differential pressure. The major field problem with this particular system is that gellation takes place rapidly and the plug has to be displaced into location within a very short time for it to be able to form a coherent barrier.

Gel technology has also been used extensively by Nowsco in the pipeline commissioning field, where both aqueous and hydrocarbon systems were used to clean, pig and lay down chemicals on pipelines, at the time of commissioning, and also subsequently during their operational life.

Using this experience as a database, it was decided to develop a gel system which could be pumped into place, where the gel would have a controlled gellation time and an controlled viscosity, enabling it temporarily to isolate a pipeline system.

The design criteria also called for the life of the gel plug to be accurately determined; this was carried out by chemically controlling the degradation of the gel after a predetermined time. To enable the testing to take place, pipeline test loops were built and extensive research undertaken in the laboratory in the UK. The test loop design was slightly unusual in so much that air-actuated valves allowed the gel train to go round the loop continuously, simulating the passage of gel down a line of whatever length was required. For practical purposes, we utilized a gel system inside an 8-in test loop, and for the tests it was determined that the train would be displaced 20km, prior to slowing the gel train, and allowing it to hydrate.

Pig-into-place plugs and slugs

A large variety of different gel formulations and concentrations were evaluated both in the test loop and also in the laboratory. During the testing programme, the following parameters were evaluated:

1. the length of time required for the gel to hydrate;
2. the effect of dynamic transport of the gel along the pipeline;
3. the gellation characteristics of the gel once transportation had stopped and the gel was allowed to sit and develop;
4. the effect of biocide in the gel;
5. the time required to break the gel, and the break mechanisms required to be employed.

At the present time, Nowsco has developed a gel with the following characteristics:

1. the gel can be mixed and injected into a pipeline in a controlled manner;
2. the gellation time can be accurately controlled for anywhere between 2 and 18 hours;
3. the viscosity of the gel can be accurately controlled, enabling known differential pressures to be withstood;
4. the gel will break within a predetermined time, enabling its removal from the system.

In the experiments undertaken in the laboratory and field loops, a 50-ft plug of gel was able to withstand 10-bar differential pressure for 52 days. Additional work is continuing with this system, but at present a low-pressure differential barrier system is available for systems where water contamination is not considered a serious problem.

As an alternative to aqueous-based gel systems, hydrocarbon gels were also evaluated. The advantage of using hydrocarbon systems is that no water is introduced into the line, no bacterial potential exists, and therefore the recommissioning process following the positioning of the barrier in the system is quicker and cheaper, as water contamination of the system is minimized. In early experiments it was attempted to develop hydrocarbon-based gel with similar characteristics to the aqueous-based gel. This research proved more complicated, due to the nature of both the hydrocarbon fluids and the base chemicals, and it has proved significantly more difficult to obtain repeatable results using the hydrocarbon-based system; research, though, is continuing. It was thought at this time that the possibility of developing a

hydrocarbon fluid which had the physical property of expansion when subjected to low temperatures within the pipeline system was a potential isolation technique.

PIPE FREEZING

Nowasco was contracted to develop a remote pipe-freezing system capable of undertaking one or more pipeline freezes simultaneously, each freeze being remote from the freeze cooling equipment. The technique was originally designed for subsea freezing and line isolation, but also has many applications in production and transmission systems. In this technique the fluid to be frozen would be displaced through the pipeline and arrested conventionally, and a freeze jacket installed around the outside of the line would allow cooling to take place at a localized position, in a controlled manner.

Pipe-freezing techniques have been available for a number of years, and usually involve either liquid nitrogen or carbon dioxide as the cooling medium, which are externally applied to the area of pipeline to be frozen. The fluids inside the line, usually water, are reduced in temperature until they form solid plugs. Experience has shown that these plugs are capable of withstanding very high differential pressures, and pipe freezing has become a relatively-common technique.

In the applications envisaged by Nowasco, it was considered that controllability of the freeze was desirable, and therefore the design criteria called for the freeze temperature on the outside of the pipe to be controlled to $\pm 1^{\circ}\text{C}$. It has been shown that even though low temperatures do not permanently impair the pipeline steel, it becomes very brittle during the operation, and therefore some potential clients would be happier not to go below -40°C for many of the operations considered. At the same time, it was envisaged that a number of freezes would be applied rather than a single freeze, and the temperature of all the freezes would be controlled remotely from a single point, minimizing the number of operators required to undertake the operation. Alarms were also required to be built into the system to monitor deviations in circulating fluid temperatures. There have been examples in pipe-freezing operations in the North Sea where liquid nitrogen had been withdrawn from a vessel at a low rate on a continuous basis and passed through small-diameter cryogenic hoses to a conventional freezing jacket. Ambient heat had vaporised the nitrogen to a gas, and cool gas had been circulating around the jacket rather than the intended liquid.

Pig-into-place plugs and slugs

As failure of the plug could have severe consequences, freeze monitoring is considered essential, and the system developed by Nowsco has been designed to overcome these potential problems. The system comprises a uniquely-designed jacket which is placed around the pipeline to be frozen. A pair of special circulation hoses are connected from the jacket via a circulating pump to a heat exchanger; the coolant is circulated continuously around the system and, as it passes through the heat exchanger, liquid nitrogen on one side of the exchanger reduces the temperature of the coolant fluid, enabling the surface temperature of the pipe to be reduced. Computer simulation of cooldowns has enabled the inner core temperature of the plug to be predicted, in different operating environments with various internal and external temperatures.

A significant amount of work was undertaken to determine the best fluids to be used for the freezing operation, both in the laboratory and in field trials. Obviously water can be successfully frozen, and has been in the past; a significant amount of research was therefore centred on developing a hydrocarbon fluid which when cooled expanded rather than contracted, and an acceptable fluid has now been identified.

To ensure that no voids are present in the pipe once the freeze fluid has been displaced to its correct location, the use of gels to increase the viscosity of the freeze fluid was evaluated. It was found that by gelling the fluid, void spaces which were potentially present at the top of the liquid were minimized. Operationally, the fluids were pigged into place in a pipeline train rather than just relying on a single pig to provide the barrier between the freezing fluids and the displacement fluid. Trials have been undertaken in 20-in pipe loops where hydrocarbon-based gels have been frozen to -40°C and withstood a 500-psi differential; in aqueous-based trials, 1,000psi differential pressures have been withstood.

The minimum pipe-freeze length which has been employed traditionally in pipe freezing has been three times the pipeline diameter, but in the field tests undertaken this had been reduced to no more than 1.5 times pipe diameter; however, wherever possible 3D plugs should be used. Obviously, where very high differential pressures are to be withstood, the strength of the plug is directly related to the diameter of the freeze and the length of the plug, as well as to the structural composition of the frozen fluid.

GELS AND HIGH-SEALANT PIGS

The Nowsco group of companies has recently developed and deployed a high-sealing high-pressure bi-directional pig train utilizing modified pipeline

pigs and high-viscosity gels. Basically a combination of gels, non-aqueous fluid, and nitrogen is used to position the train in a pipeline and form a isolation barrier. In one particular example it allowed the client to install 32-in valves onto an existing pipeline without decommissioning the system. The gels, fluid and nitrogen provide sealing to prevent by-pass of hydrocarbon gas in the pipeline and prevent fluid loss from in front of the pig train into the pipeline. The technique was developed during extensive full-size onshore trials, where it was seen that modified conventional pigs could withstand high differential pressures, in some cases in excess of 90psi. The offshore operation was deemed successful by all parties concerned; not only did the pig train hold the required differential pressure, but also minimal fluid loss and no gas by-pass was observed during the complete operation, which lasted in excess of a month. Upon receipt of the pig train back at the platform the job was deemed completed, and a complete success.

PACKER PIG

Nowasco has been awarded the license from Dowasue Industries of Canada to market and operate its pipeline packer pig systems. Dowasue has had success utilizing its umbilical/rodset packers in pipelines where high differential pressure isolation has been required. Nowasco's operational requirement, a modification of the existing technology, was necessary to enable the systems to be acceptable for use in the applications envisaged in the North Sea and Europe. At the present time, a 12-in free-swimming packer is available; this can be dispatched from the pig launcher conventionally and, once at the correct location, the pig can be stopped in the pipeline and the tool set. The pig then can be used to isolate the pipeline against high differential pressure. On completion, the tool is released and pigged either back to the platform or along the length of the pipeline to the pig trap. Nowasco has been extensively involved in the development of the systems required to make this tool usable for fully-remote pipeline operations; this has included the development and inclusion of tracking systems to ensure that the pig's position is known at all times. For North Sea applications, it was considered that a replacement to the existing setting control commands of the packer would have to be developed, as well as equipment to determine and monitor the internal pressures within the system.

We also required to know not only that the pig was set and holding pressure, but that no internal seals were leaking and that the pig was not likely to release itself unexpectedly. The setting command mechanism which was

Pig-into-place plugs and slugs

previously utilized was not considered reliable enough for subsea applications, requiring an acoustic interrogation system to be developed.

The pig consists of a series of brake shoes arranged around the packer module and a sealing ring; on receipt of the command signal, the packer pushes the brake shoes out against the pipe wall and also compresses the sealing ring. The compressed ring is squeezed against the pipe wall and therefore isolates the pipeline. Tests have shown that the tool is capable of withstanding 1000psi differential pressure.

Nowasco is undertaking helium/nitrogen leak detection on the pressure side of the packer to determine its long-term ability to resist by-pass of gas. A 34-in packer will be deployed in the North Sea for pipeline isolation during the 1990 season.

CONCLUSION

A number of alternatives are now available to operators requiring the isolation of pipelines, each system being designed to be used independently or in conjunction with others to safely isolate a pipeline. Work is continuing on the refinement of these techniques.

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PIGGING FOR PIPELINE INTEGRITY ANALYSIS

THE DOT has collected and assimilated data on pipeline incidents for many years. A pipeline incident is defined by the DOT as having one of the following characteristics:

- 1) An event that involves a release of gas from a pipeline or of LNG or gas from an LNG facility, and
 - i) a fatality or personal injury necessitating in-patient hospitalization; or
 - ii) estimated property damage, including costs of gas lost by the operator or others, or both, of \$50,000 or more.
- 2) An event that results in an emergency shut-down of an LNG facility.
- 3) An event that is significant, in the judgment of the operator, even though it did not meet the criteria of paragraphs (1) or (2) above.

Table 1 sets out the statistics that cover the 1989 incidents for liquid pipelines. Most pipeline operators' major concern is the mitigation of corrosion, but as can be seen from this chart, corrosion is not the major cause of incidents. In fact, corrosion (internal and external combined) accounts for 19.88% of the incidents. Outside force is the number-one contributor, with 26.71%[1].

Table 1-A gives the same statistics for gas pipelines[2], which show the same trend with 4.67% of the incidents caused by corrosion and 49.02% caused from outside force.

This phenomenon is not unusual, and is proven to be true with all past reports of DOT data. This fact is shown in the reports made by Battelle to the AGA for the period 1970 to 1984[3], and 1984 to 1987[4].

In the case of the 1970 to 1984 incidents, Battelle's analysis reported 53.6% of incidents were related to outside force. In comparison, corrosion ac-

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INCIDENT SUMMARY BY CAUSE

CAUSE	# OF INCIDENTS	% OF TOTAL	BARRELS LOST	PROPERTY DAMAGES	% OF TOTAL	DEATHS	INJURIES
Internal Corrosion	5	3.11	750	20,440	0.28	0	0
External Corrosion	27	16.77	18,263	491,655	6.79	0	0
Defective Weld	7	4.35	8,408	343,000	4.73	0	0
Incorrect Operation	9	5.59	4,391	94,609	1.31	0	3
Defective Pipe	13	8.07	80,161	766,523	10.58	0	0
Outside Damage	43	26.71	44,461	2,457,904	33.92	2	32
Malf. of Equipment	8	4.97	3,260	526,020	7.26	0	0
Other	49	30.43	41,550	2,545,014	35.13	1	3
TOTAL	161	100.00	201,244	7,245,165	100.00	3	38

SOURCE: DOT/DOTFORM 7000-1 02/06/1990

Table 1. Summary of liquid pipeline incident reports received in 1989.

counted for 16.9%. The 1984 to 1987 report broke the report into offshore and onshore, with outside force responsible for 39.0% onshore and 37.0% offshore. Corrosion incidents for the same period were 24.0% onshore and 35.0% offshore. This, together with the 1989 data, covers a 19-year span where outside force caused a major portion of reportable incidents.

The above data would support the need for an ILI device that would accurately locate and quantitatively identify areas of concern. In addition to known data, there is always the question of how many times pipelines are affected by outside force that are not reportable incidents. A more important question for the operator is, "Has the pipeline been affected or is it being affected by outside force that I am unaware of?"

With these questions and statistics as a guide, Vetco Pipeline Service embarked on a development process to design a ILI tool that would fulfil this need.

In the development stage of the project, the goal of both quantitative and qualitative data acquisition and analysis was foremost. This goal has been achieved.

Pigging for pipeline integrity analysis

INCIDENT SUMMARY BY CAUSE

CAUSE	# OF	%OF	PROPERTY	DEATHS	INJURIES
	INCIDENTS	TOTAL	DAMAGES		
Internal Corrosion	12	4.67	1,125,149	0	0
External Corrosion	24	9.34	999,909	3	2
Damage from Outside Forces	126	49.02	11,332,866	16	42
Construction/Material Defect	20	7.78	1,160,554	2	4
Accidentally Caused by Operator	8	3.12	400,000	0	9
Other	67	26.07	12,059,120	15	21
TOTAL	257	100.00	27,077,598	36	68

SOURCE: DOT/DOTORRSPAF7100.1/F7100.2

Table 1-A. Summary of natural gas pipeline incident reports received in 1989.

TOOL DESCRIPTION

Fig.1 shows the VPSI 36-in deformation/slope (D/S) tool. Each tool carries multiple sensors mounted in two rings to ensure 360° coverage of the pipe body wall. In addition, the overlap and offset of the sensors allows two separate views of the same defect area.

Each sensor is individually monitored and recorded. This allows 180° comparison of data: i.e. the 12 o'clock and the 6 o'clock, the 10 o'clock and the 7 o'clock positions, etc. In doing this, the tool centreline position, in the pipeline, can be monitored and factored into the defect data.

The sensors measure from a zero point at the ID of the pipeline. As the sensor traverses the line, it is allowed to move both outward or inward. This movement is converted to electronic data for storage in the on-board recorder.

The recorder is capable of storing data for a complete recording of the entire pipeline. Total capture of all the raw data allows complete analysis of

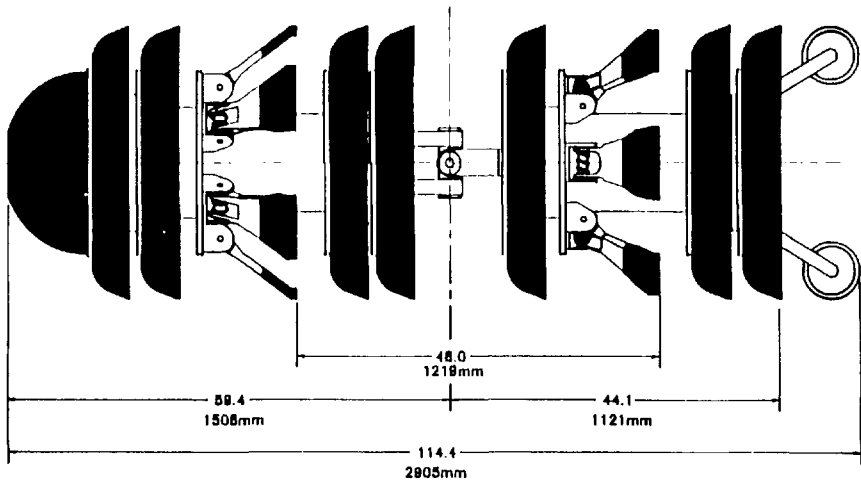


Fig.1. 36-in deformation tool.

the system's performance for the most minute changes. This allows year-to-year comparison of data, to allow the operator to see change as the change occurs and mitigate the cause.

Tool packaging is field proven. In fact, this design of equipment has successfully logged in excess of 16,000miles of pipeline. Most of these miles were in extremely-hostile pipeline environments. The longest single run of an ILI tool was accomplished by this unit when it logged 635miles of 40-in pipeline in a single pass.

TOOL CAPABILITIES

The D/S tool is capable of running in crude oil, refined products, natural gas, and other petroleum products. In addition to petroleum, the D/S tool can be run in many other atmospheres, such as compressed air or water.

Desire by operators to better detect and identify mechanical anomalies, pipeline configuration, temperatures and pressure profiles and change in pipeline position is not new. An ILI tool that has the capabilities to answer the operators' requirements has been a requirement that could not be met until now.

Pigging for pipeline integrity analysis

Earth Movements	Improper Construction
Sea Currents	Hydrostatic Tests
Wash Outs	Improper Back Fill
Mechanical Interference	Unsupported Spans

Table 2. Deformation/slope change cause factors.

Dents	Ovality
Mashes	Construction Damage
Wrinkles	Third Party Damage
Buckles	Flat Spots
Generalized ID Changes	Hydrostatic Test Expansions

Table 3. Defect detection capability.

Girth Welds	Insulating Flanges
Valves	Spiral Welds
Tee's	Scraper Detectors
Transition Joints	Stopples Fittings

Table 4. Pipeline appurtenance detection.

Deformation of the pipeline can be caused by mechanical force (ditching machines, anchors, etc.) or by a change in slope. The D/S tool is sensitive to both types of change. Table 2 lists some of the causes that effect the area or slope of the pipeline. Table 3 lists some of the mechanical defects that are detectable.

In addition to deformation or mechanical damage, the log clearly indicates many other pipeline appurtenances which help in defining pipeline configuration. Some of the appurtenances detected are listed as the second part of Table 4.

Tables 3 and 4 are not inclusive of all deformation, mechanical damage or pipeline appurtenances that can be detected, but provide an indication of the tool's ability. The D/S tool is sensitive to any factor that would cause a change in the pipeline ID or change in direction of travel.

The tool cannot 'see' the cause of the pipeline change, but rather looks at symptoms. Symptoms can then lead the operator to a cause.

In addition to the capabilities described above, the tool has options that allow further definition of the pipeline system. A brief description of each option follows:

Pipeline Pigging Technology

Vertical displacement - electronic monitoring of the tool movement can plot changes in the vertical plane of the pipeline. This data is used to determine sag or heave, which can be related to the earth movement caused by ocean currents, unsupported spans in wash outs, frost heave or thaw, earthquake, landslide, etc. Pipeline movement of this nature is nearly always accompanied by deformation of the pipeline. Degrees of angle change in slope is computable.

Horizontal displacement - very similar to sag or heave, only in a different plane.

Bend location - monitoring tool movement on the vertical and horizontal axes gives the ability to define pipeline bends as over, under, left or right. In addition, the degree of this change of direction can be computed.

Orientation - the tool position related to pipeline o'clock position is recorded. Orientation information allows the identification of the transverse location of the anomaly.

Product temperature - continuous temperature profile of the pipeline. Temperature data is used in determining such things as:

- coating performance;
- assigning risk priority to certain pipeline area in material degradation studies, such as SCC attack;
- efficiency studies for heated lines;
- defining areas of concern for solids' suspension drop-out, such as paraffin, asphaltines, NGL liquids, etc.;
- determining efficiency and amounts of certain types of inhibitor programmes.

Product pressure - continuous pressure profile of the pipeline is used primarily in efficiency studies affecting pumps and/or compressors. Studies such as this can help determine the need for changes in HP requirements or location of future pumping or compressor locations.

Above-ground markers - location of areas along the pipeline is accomplished by a lightweight, compact, weatherproof and accurate AGM system.

INFORMATION AND DATA HANDLING

The data derived from the sensing system listed above is stored on magnetic tape and can be processed by several methods. The foremost of these is by computer.

Pigging for pipeline integrity analysis

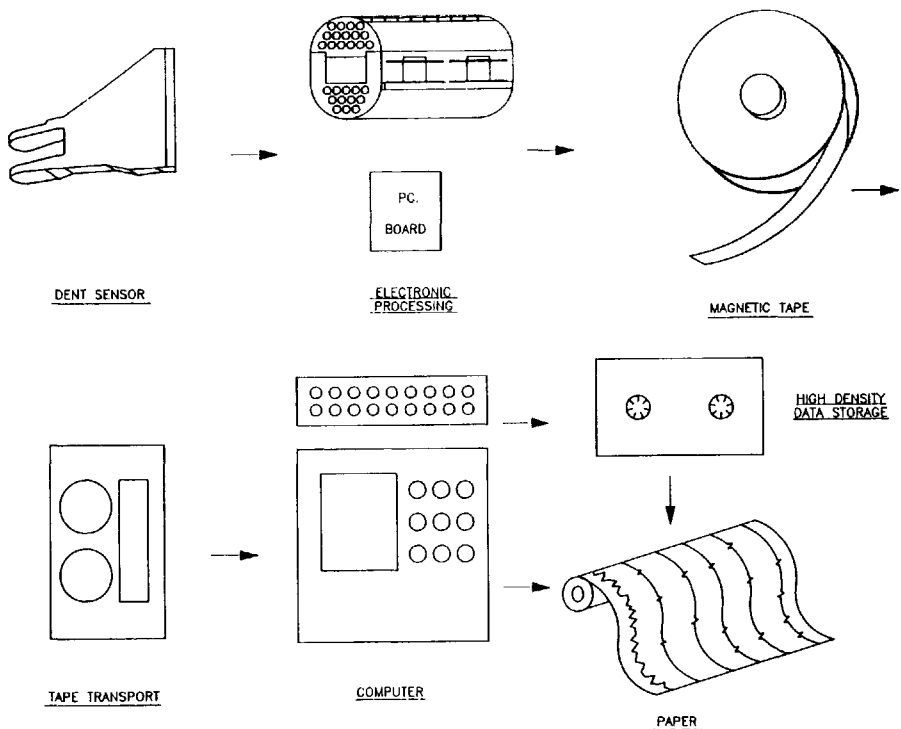


Fig.2. Data flow schematic.

Fig.2 shows a schematic of the flow of data from the sensor to the final product. As can be seen, the information can be downloaded directly to computer. Once the information is on the computer, then it can go into direct evaluation, or to a paper hard copy which can then be evaluated. With the proper hardware, clients can direct-print any log segment from the digital data stored in the computer.

Clients can elect the method they prefer for data handling. Should they elect for the data to be supplied on high-density cassette, then this will require an in-house computer capability based on Novel Network 386 serving on a 33MHz computer or a Compaq System Pro.

Using the computer system, the operator will have many options at his finger tips. Data will be available on random access. The operator can identify an area to be viewed and the computer will automatically go to the area.

The computer data can be viewed in a selectable scale and at a selectable speed. Individual areas can be viewed or the operator can scroll through the

Pipeline Pigging Technology

<u>Operating Temperature Range</u> :	32 to 160 Degrees Fahrenheit 0 to 70 Degrees Celsius
<u>Record Hours</u> :	102 Hours Normal 204 Hours Special
<u>Tool Speed Range</u> :	0.5 to 15.0 Miles/Hour 0.8 to 24.0 Kilometers/Hour
<u>Optimum Speed Range</u> :	2.0 to 8.0 Miles/Hour 3.0 to 13.0 Kilometers/Hour A constant speed is most desirable
<u>Maximum Operating Pressure</u> :	1500 Lbs./Sq. Inch 70 Kilopascals
<u>Distance Accuracy</u> :	Dual Odometer Sensors 1 Ft/1000 Ft
<u>Timing Device</u> :	On board device for timed phase runs
<u>Detection Channels</u> :	Multiple Deformation 2 Distance Measuring 1 Temperature 1 Orientation 1 Slope 1 Horizontal Bend 1 Vertical Bend
<u>Products</u> :	Crude Oil, Natural Gas, Fuel Oils, Other Liquids or Gas

Table 5. Vetco deformation tool: general data.

data. The pipeline is available to the operator end-to-end at the computer workstation for any purpose his operation or maintenance may require.

Temperature, pressure, slope and defect information can be displayed on the screen with the data, or graphically displayed for the entire line. Notes can be added to a file that will always follow the pipeline location. This feature allows the operator to view prior history notes with a simple key stroke. Notes might contain information on origin of defect, repair made, defect growth, etc.

Sensitivity :	Deformation: $\pm 1/8$ (.125") (3.17 mm)
	Span: 7" (radius + 2, radius - 5)
	Minimum Detectable Deformity Shape:
	1" long x 1" wide dent (2.54 cm x 2.54 cm)
	2" long x 7" wide bulge (5.08 cm x 27.78 cm)
	Temperature: 0 - 70° C $\pm .5^\circ$
	Distance: $\pm 1/10$ percent
	Orientation: $1^\circ \pm 1$ percent
	Slope: $1^\circ \pm 1$ percent

Table 6.

In both the computer system and the hard-copy system, a comprehensive detailed report is supplied that lists and locates all significant defects.

TOOL OPERATIONAL DATA AND SENSITIVITY

Table 5 sets out the operational data of the D/S tools in the 20-in to 48-in range. As can be seen from this data, the tool is flexible in its design and the criteria would cover most pipeline survey needs.

Sensitivity of the tool is set out in Table 6. Total tool performance is pointed out in these two tables, and shows the tool's outstanding capabilities and flexibility.

TOOL PERFORMANCE

Fig.3 shows a typical D/S log with each channel identified as to the information it contains. Fig.4 is a schematic which shows the D/S tool as it passes through a pipeline transition. This type of anomaly is characterized by a general ID reduction; all the sensors are depicted moving inwards as the tool enters a heavy-wall section of pipeline. Fig.4-A shows how this type of anomaly looks as reproduced from actual pipeline data. The sensor movement as the tool enters the transition joint and the restriction increase until the new wall thickness is achieved can be seen. A reverse of the sensor movement shown would indicate the tool was moving from a thinner wall thickness to a heavier wall thickness.

Pipeline Pigging Technology

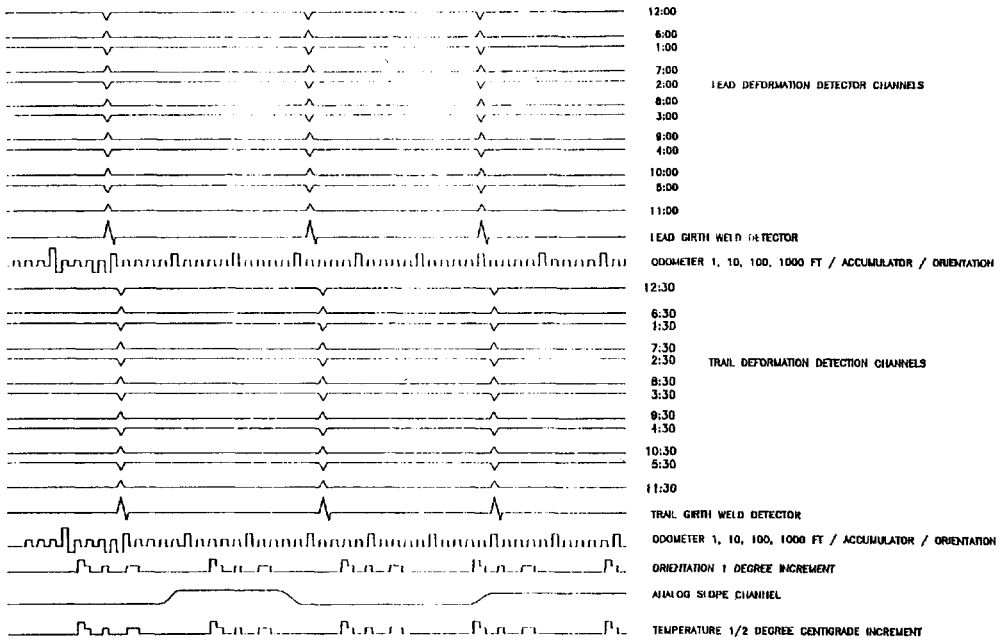


Fig.3. Typical D/S log.

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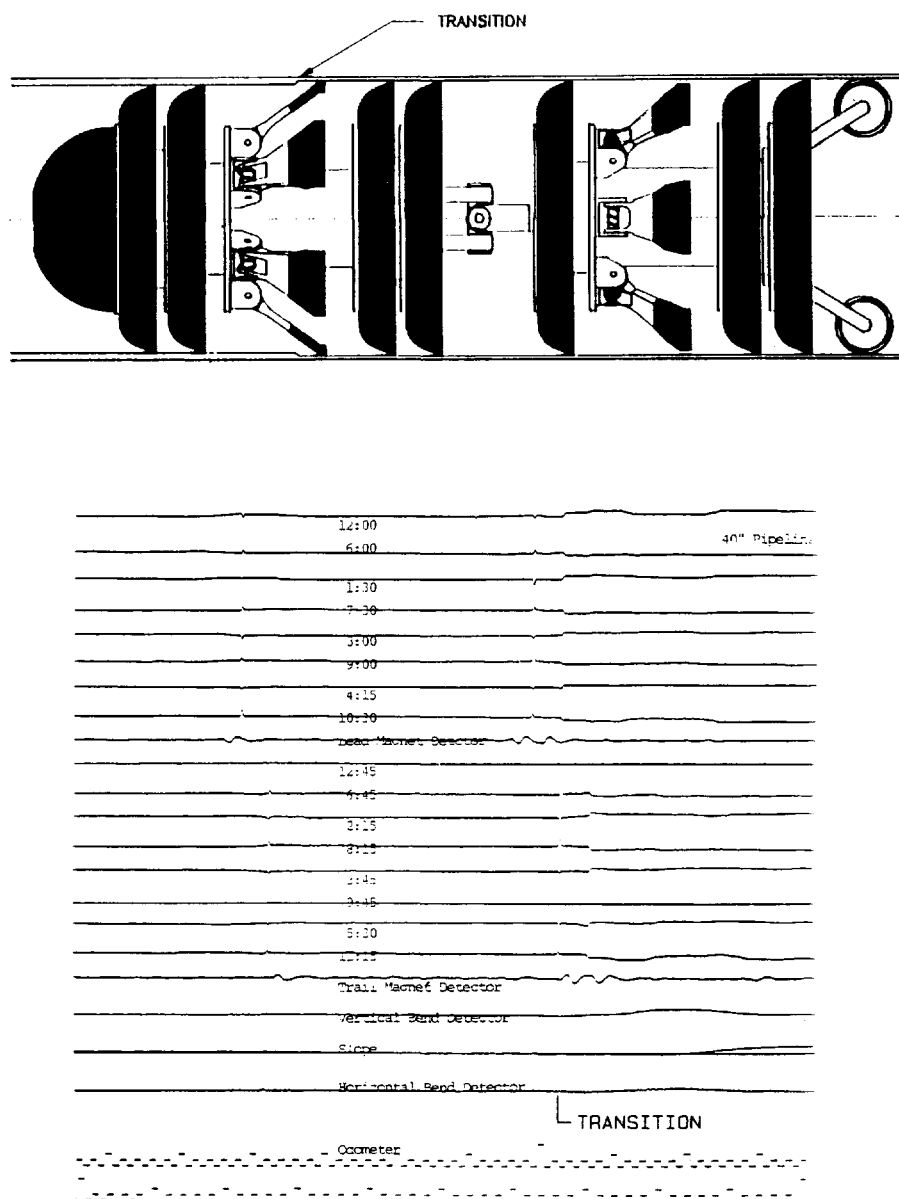


Fig.4. The D/S tool passing through a transition (top) and the accompanying chart.

Pipeline Pigging Technology

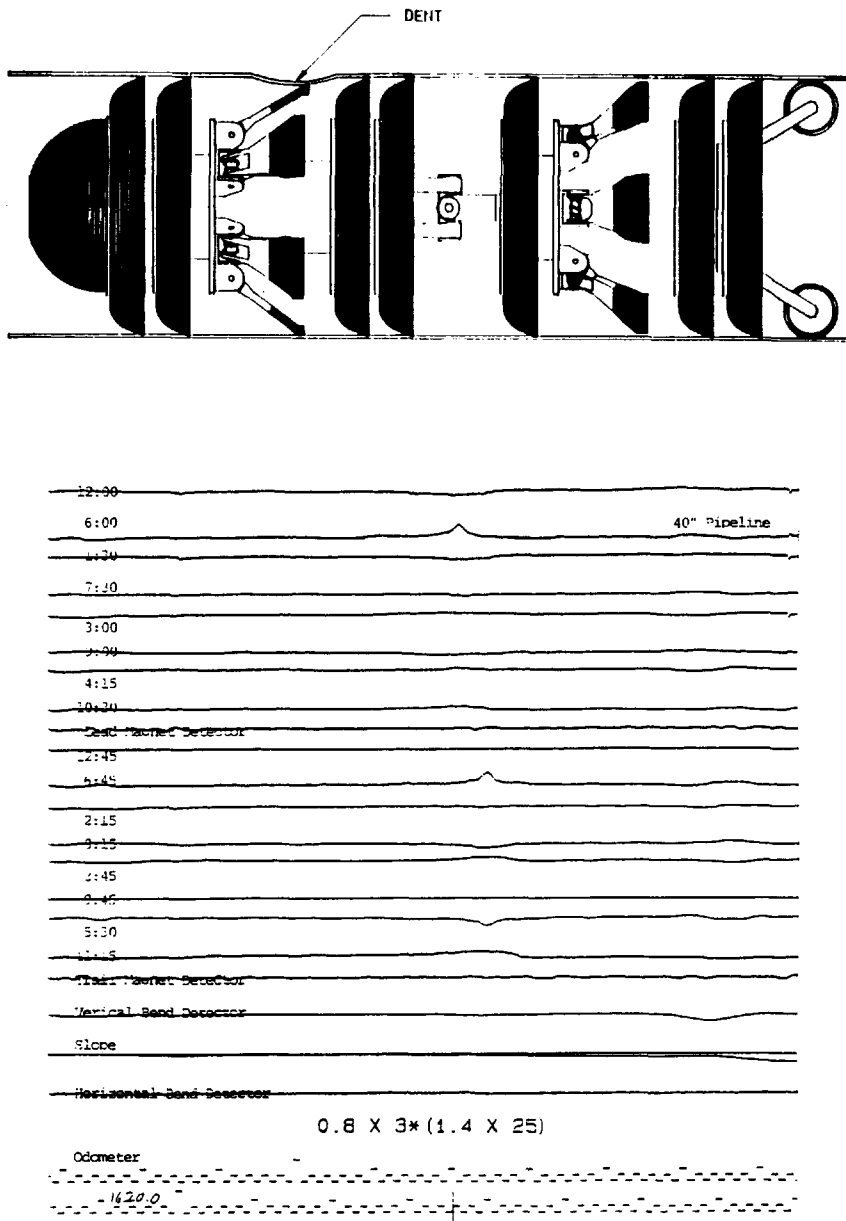


Fig.5. The D/S tool passing a dent (top) and the accompanying chart.

Pigging for pipeline integrity analysis

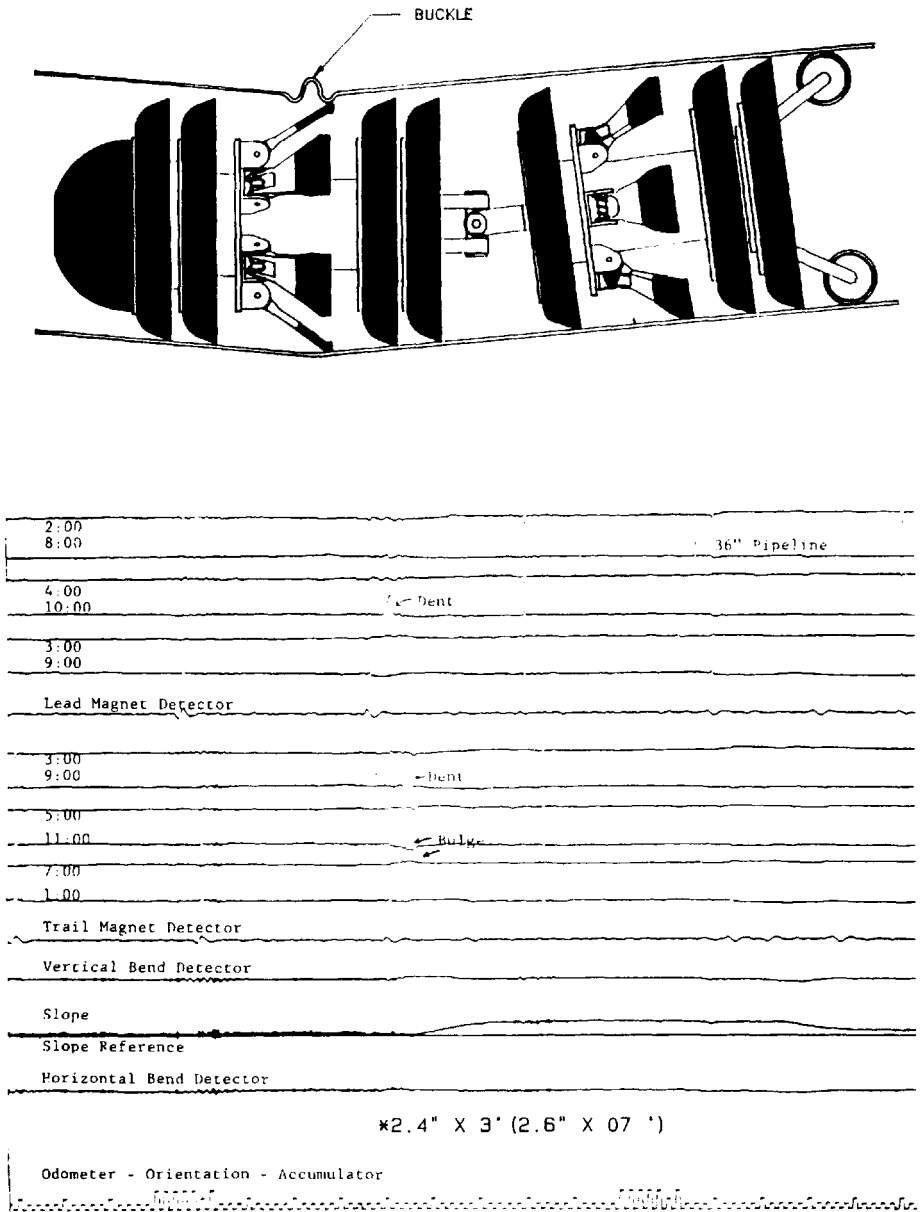


Fig.6. The D/S tool passing a buckle (top) and the accompanying chart.

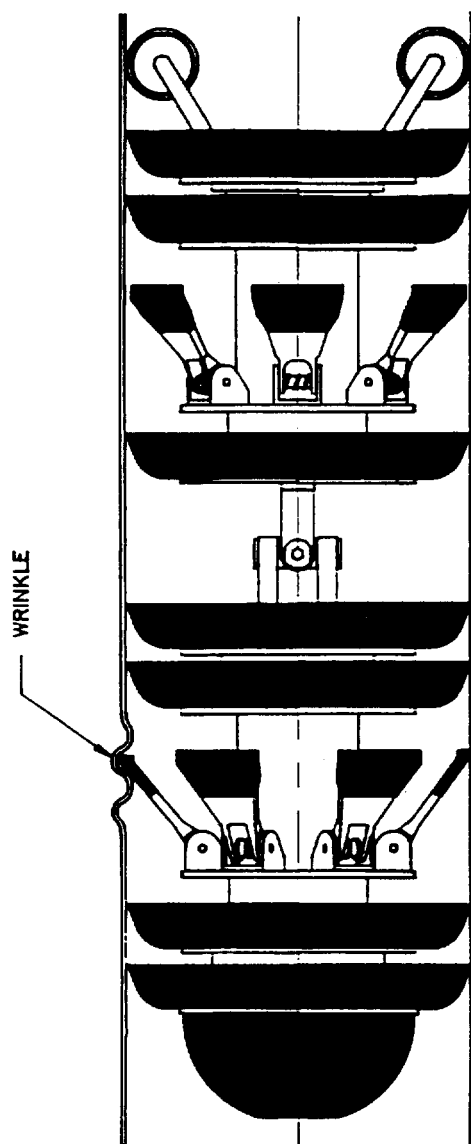


Fig.7. The D/S tool passing a wrinkle.

Pigging for pipeline integrity analysis

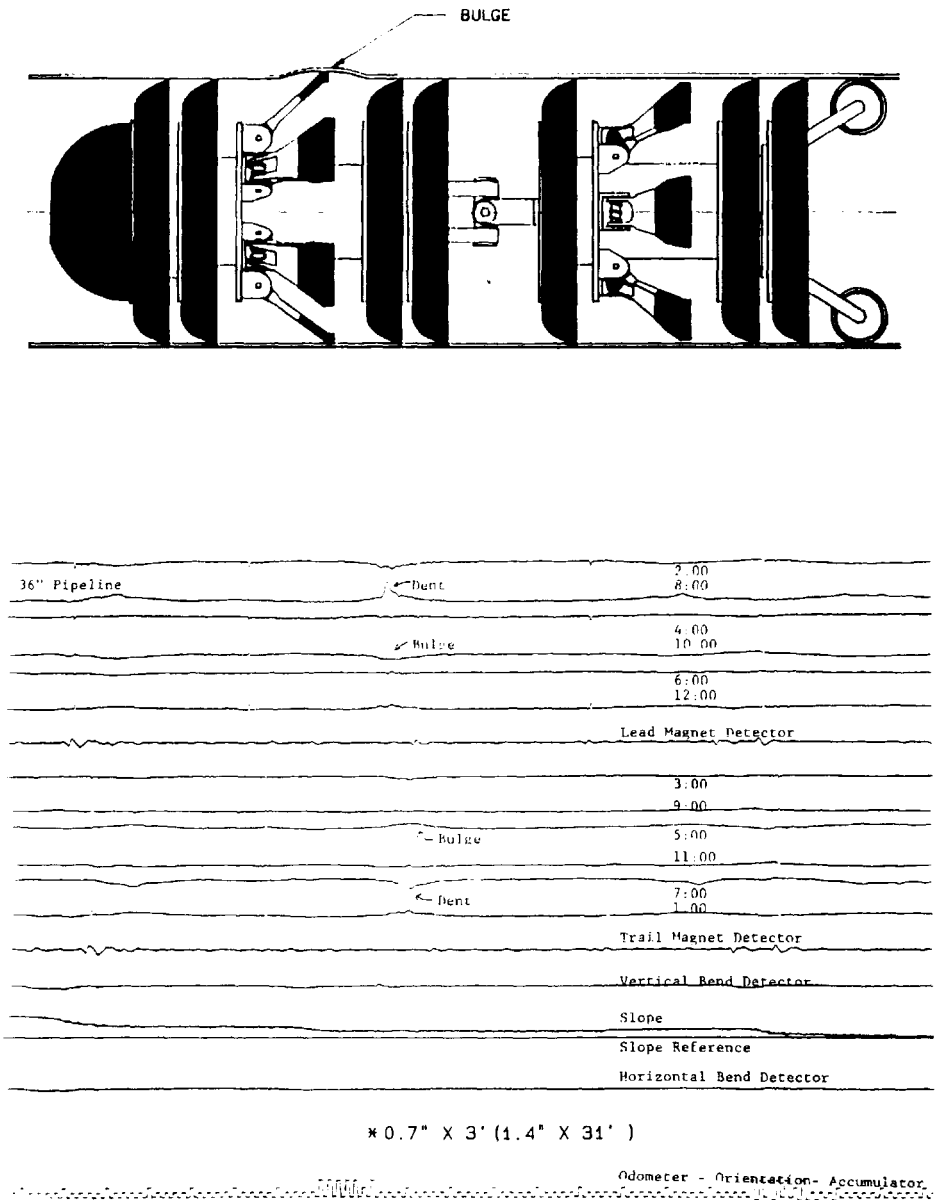
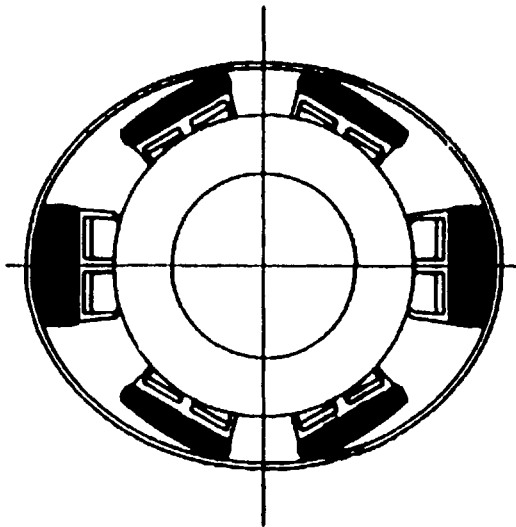
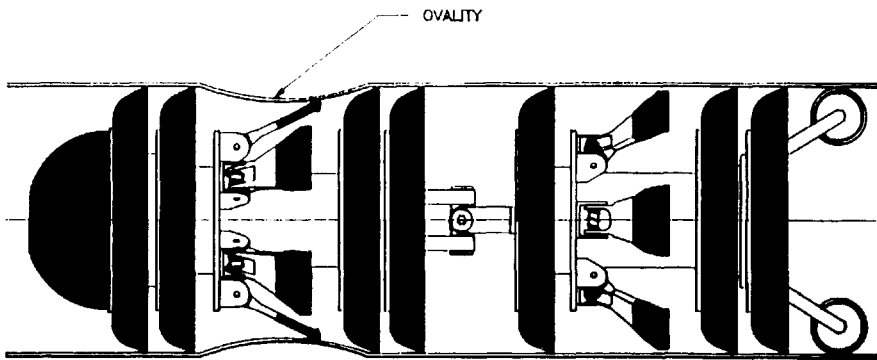


Fig.8. The D/S tool passing a bulge (top) and the accompanying chart.



OVALITY

Fig.9 (a and b). The D/S tool passing pipe ovality.

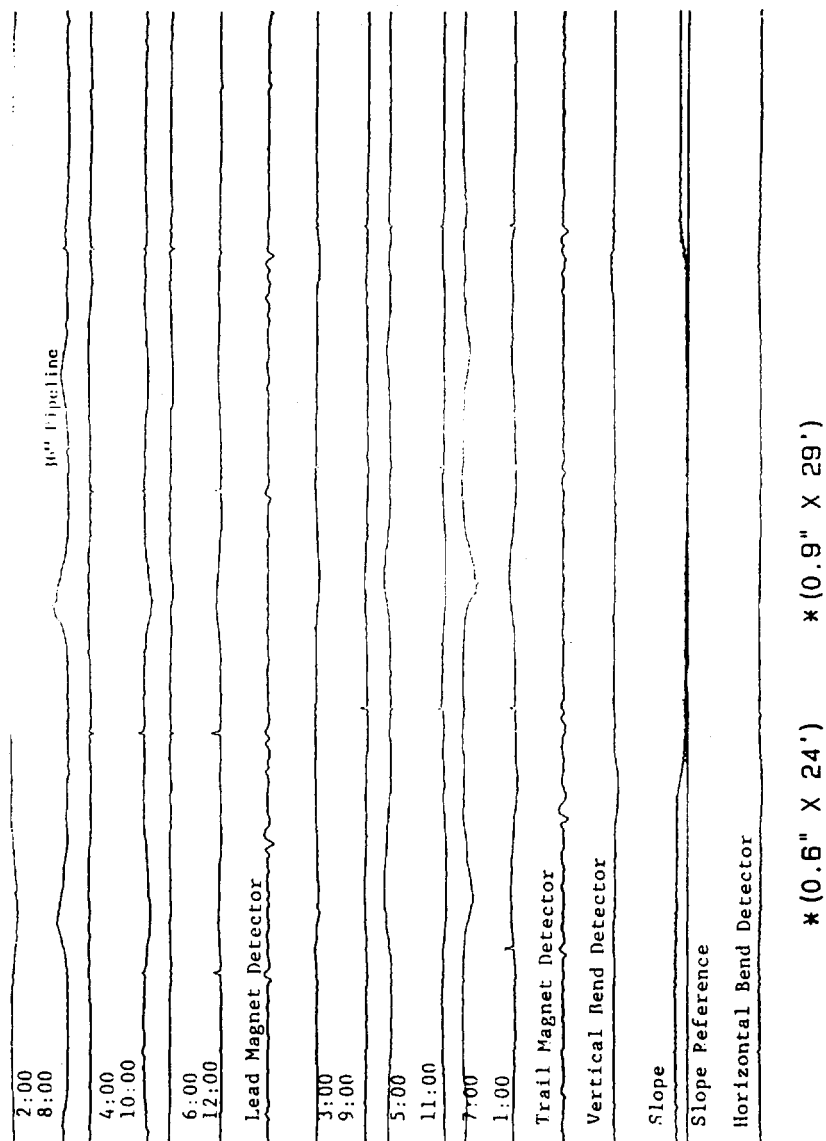


Fig.9-B.

Odometer - Orientation - Accumulator

Fig.9c. Chart from the D/S tool passing an ovality.

Fig.5 is a schematic of the tool as it passes a dent. In most cases, a dent is recorded on one or two lead sensors and one or two trail sensors. Fig.5-A shows an actual dent as recorded by the tool; the numbers at the bottom of the chart give the dent in inches of penetration by feet of longitudinal area covered; in this case, 0.7in penetration by 3ft. The second set of figures that are in parenthesis give the associated ovality in inches of penetration at the maximum deflection over the number of feet affected longitudinally; the ovality here is 1.4in by 25ft.

Fig.6 is a schematic of how the tool reacts to a buckle. An actual case study of a pipeline buckle is included later in this paper. Fig.6-A shows how the tool recorded a buckle. The number at the bottom of this log indicates the buckle feature has a maximum penetration of 2.1in over 1ft. Associated ovality is 3.0in over 11ft. This particular defect was in a 40-in crude oil pipeline, and has now been removed.

Fig.7 is a schematic of how the tool reacts to a wrinkle. As with the buckle, a case study is included in a later part of this paper.

Fig.8 shows how the Vetco log detects a bulge. An actual bulge is displayed on the log in Fig.8-A. A dent with associated bulge is the first stage of pipeline buckling. If the area depicted is being affected by dynamic forces, then a buckle will probably form at this location.

Figs 9 and 9-A shows pipeline ovality from a side view and end view. Ovality generally covers a much larger area than is depicted here, but these drawings are designed to show tool function. As shown in previous log examples, nearly all pipeline physical changes are accompanied by some form and degree of ovality. Fig.9-B shows two areas of ovality that occur in the same area.

CASE STUDY 1

The first defect we would like to look at is the buckle in a 40-in pipeline. Buckles are usually the most restrictive mechanical anomaly, and under API should be removed. Fig.10 shows the D/S information on the buckle as being 1.8in over 3ft; the associated ovality is 2.5in over 15ft. It is interesting to note that in this log example, the slope channel has deviated a maximum of 10ft starting 25ft upstream of the buckle. Also, a bulge can be seen that is a common factor in buckling. After the buckle was uncovered by the operator for repair, it was found that the tool-recorded data matched the actual defect almost exactly. In this case, the pipeline operator used the D/S data and reports to make several necessary repairs.

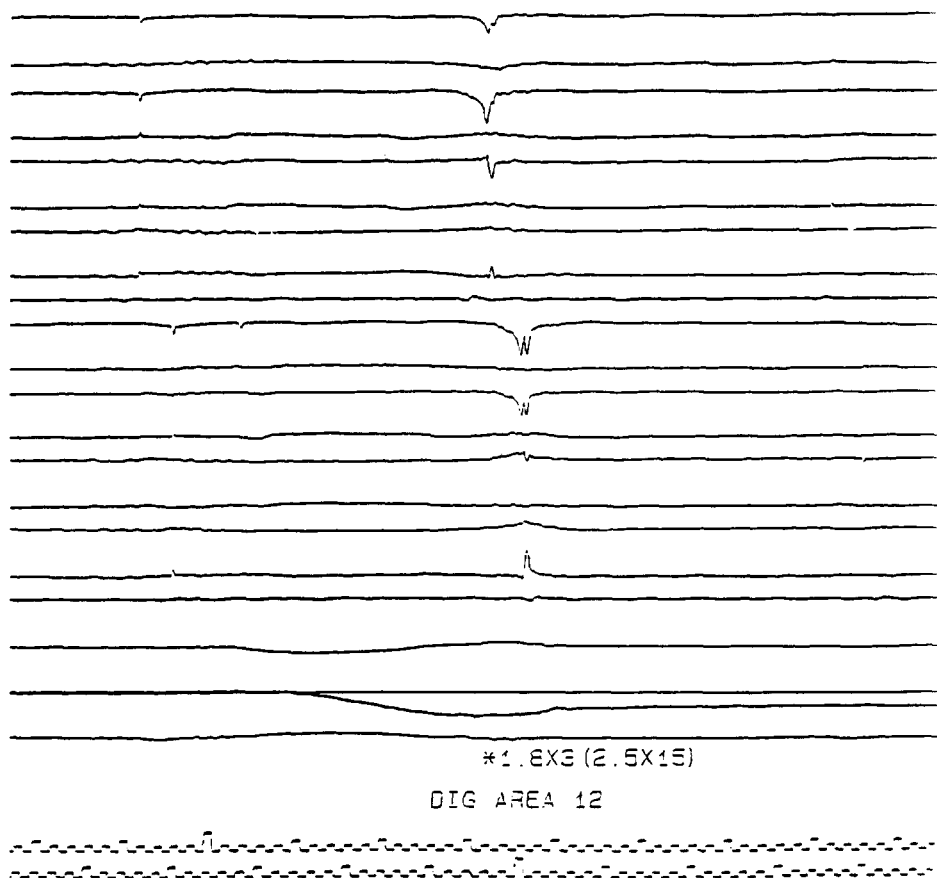


Fig.10. D/S information on a buckle (case study 1).

CASE STUDY 2

The second case is that of a 48-in pipeline. The operator was aware that this pipeline was subject to movement, and is monitoring all changes to the pipeline. In this case, dynamic forces are known to be affecting the line. The area of concern is a wave or small wrinkle that is developing on a downhill section of the pipeline, just prior to a small stream crossing. VPSI has taken this data over a several-year period to give the operator a compiled report.

The report includes numeric data that represents the different survey runs. The data is set out by year and quarter the data occurred. Data viewed in this manner point out the dynamic nature of the area. It also points out that the area has changed over the 9 years depicted, yet the change does not seem to be dramatic.

Numeric data was evaluated in conjunction with slope or vertical displacement. The slope information pointed out that no substantial changes had occurred. In fact, the data remains identical on all runs (see Figs 11, 12, 13 and 14).

Fig.11 shows the 1989 data on slope and pressure. The saw-toothed line is the raw data on slope. The smooth line along the bottom of the graph is the slope as plotted from the raw data; the top line is pressure. Each of the pipeline bends is marked on the graph at the area in which they occur. A circle approximately 75% along the line marks the area of the wrinkle.

Fig.12 shows the data from the 1990 survey. Data from both plots shows the pipeline slope has not changed. While this is for only two years, data from preceding years verified that the pipeline is remaining in the same position for several years.

Fig.13 shows the computer's ability to manipulate the data as plotted and change the scale of presentation. Fig.13 has reduced the amount of data and increased the scale to bring the operator down on the exact area of interest, the wrinkle.

Raw data is again plotted in the irregular line in the centre of the graph. The slope line is now plotted in a grid area of 10-ft by 10-ft increments.

Fig.14 carries this out to an even larger scale. In this instance, only the slope is plotted; the grid boxes remain a standard 10ft by 10ft, with the slope superimposed on the grid.

In addition to the numeric and graphic presentations, the computer can also generate a three-dimensional look at the wrinkle area. Fig.15 is a look along the pipeline at the wrinkle area.

A cross-section of the pipeline can be generated at any given area. The cross-section in Fig.16 is the maximum area of deformation in the wrinkle area.

Pigging for pipeline integrity analysis

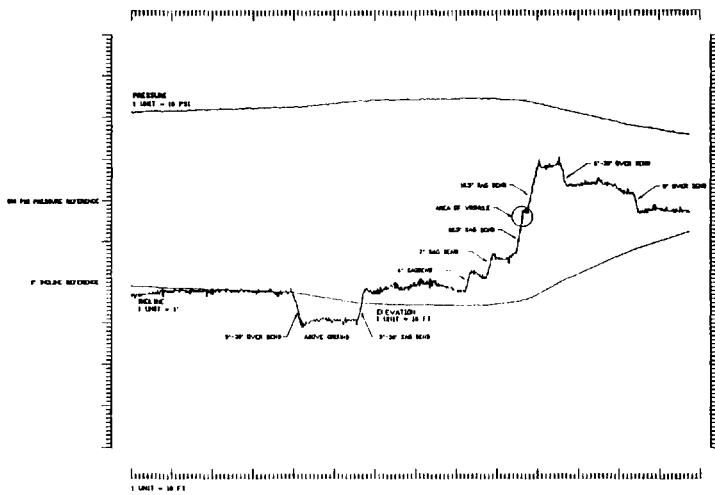


Fig. 11.

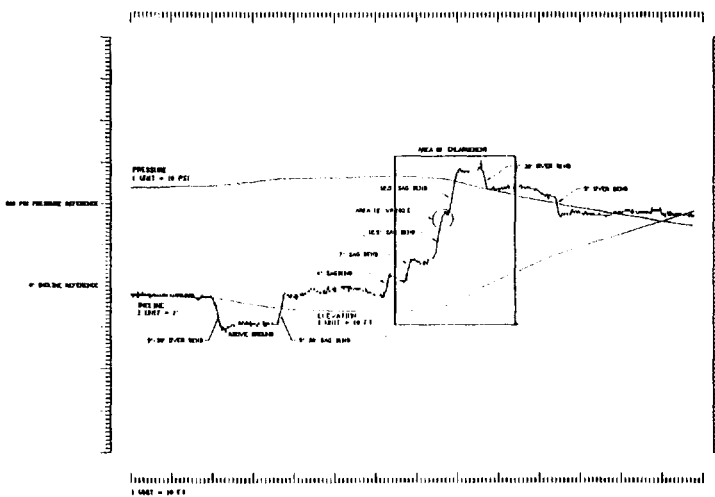


Fig.12.

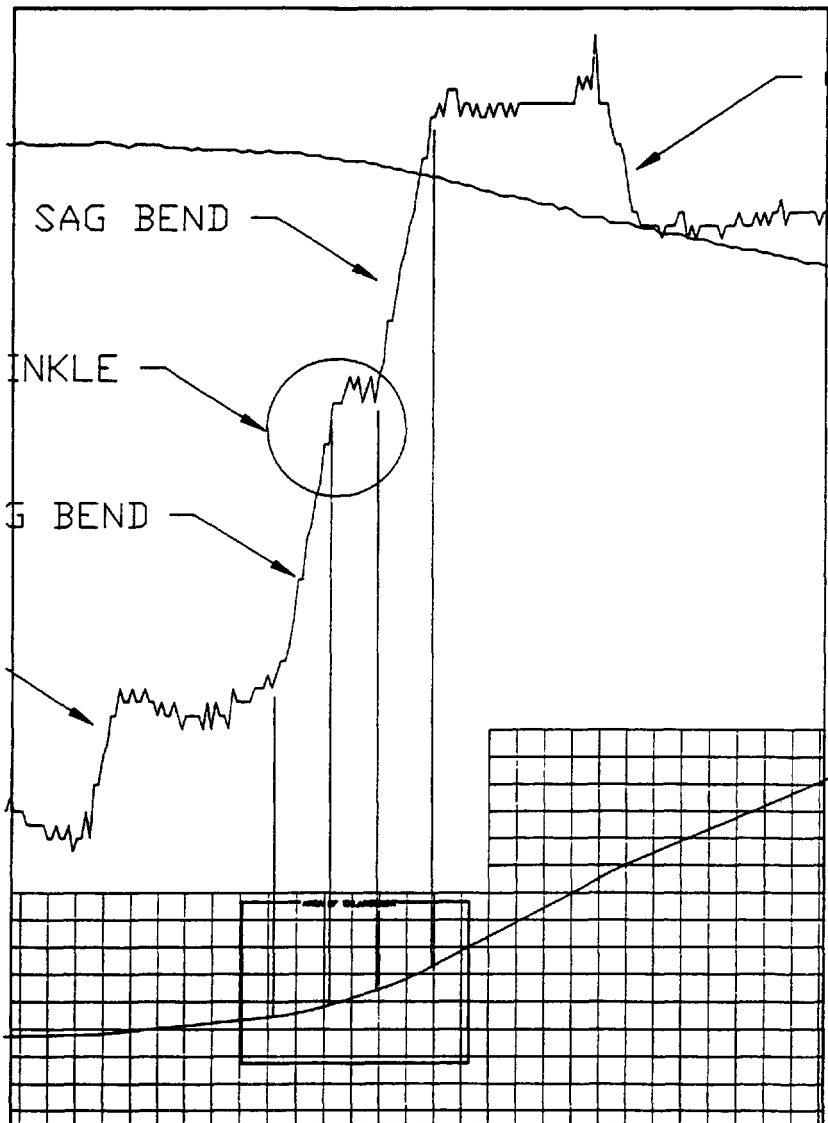


Fig.13.

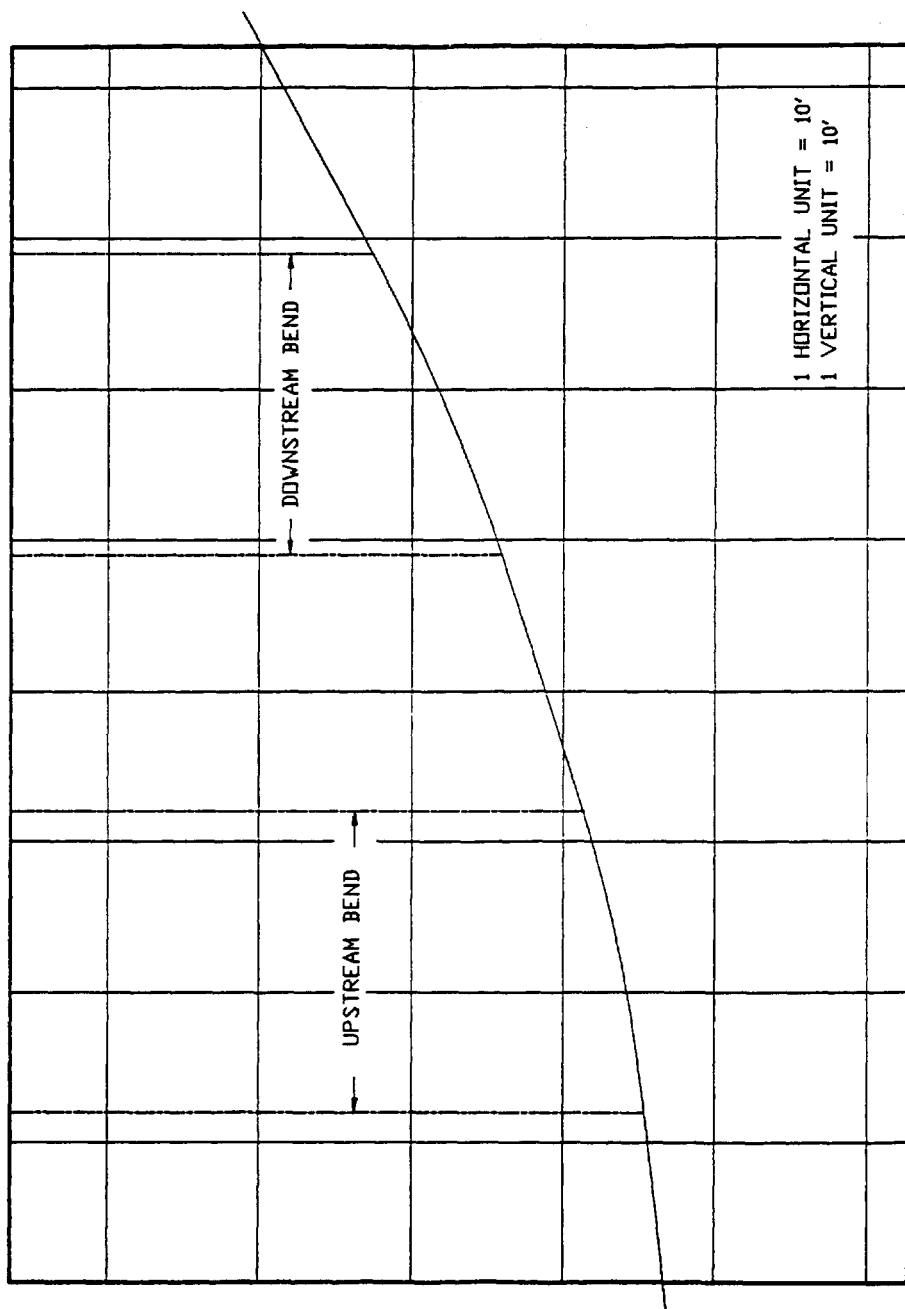


Fig.14.

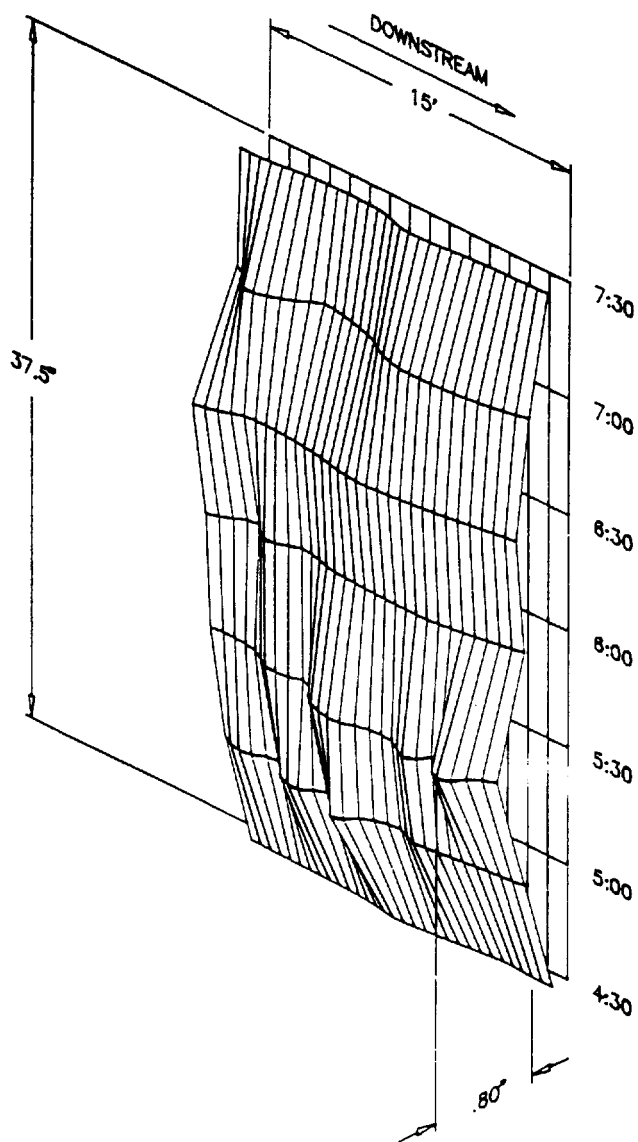


Fig.15.

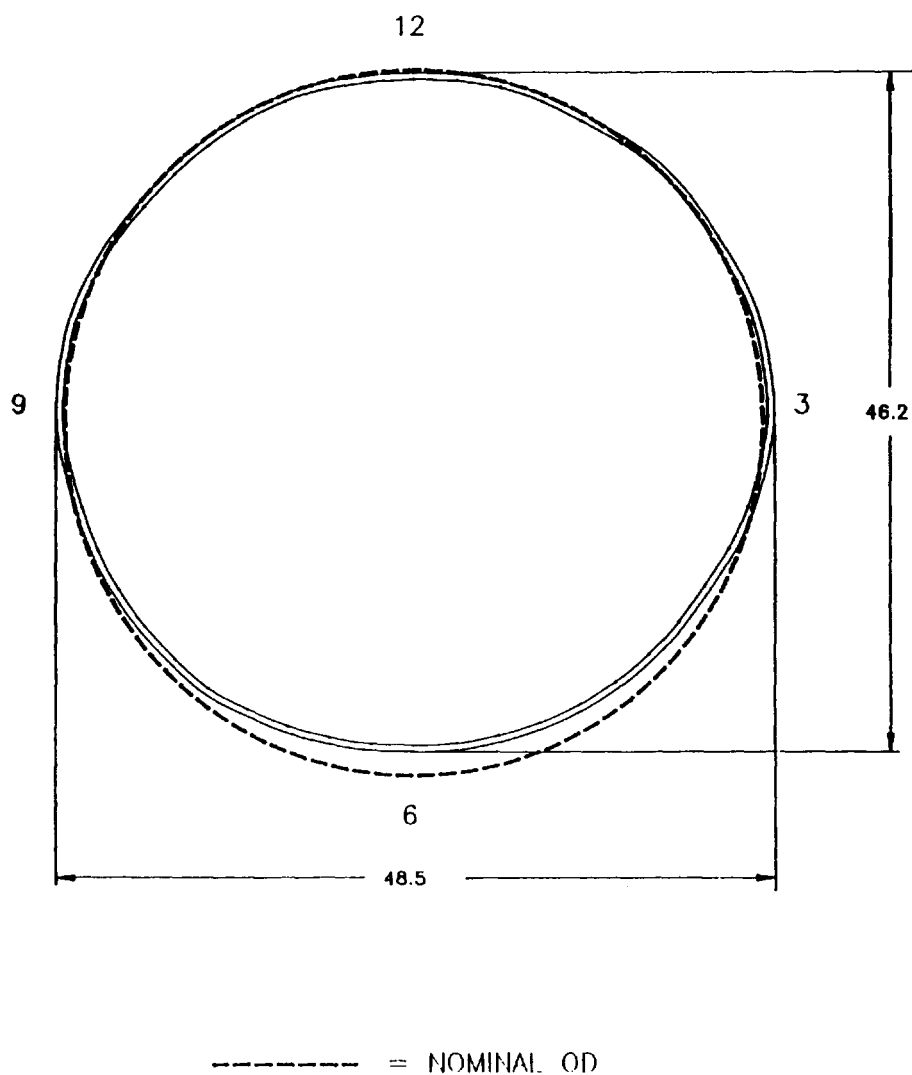


Fig.16.

CONCLUSIONS

ILI technology, as used in the D/S tool, is state-of-the-art for giving the operator conclusive data about the physical condition and changes of position in a pipeline system.

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 2. DOT: DOT ORRSPAF 7100.1, /F7100.2.
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CABLE-OPERATED AND SELF-CONTAINED ULTRASONIC PIGS

IN ORDER to establish the integrity of ageing pipelines, intelligent pigging has become of increasing interest. For several decades, pigs using magnetic stray flux were the only tools available for this purpose on the market. The need for more accurate tools was an incentive to develop ultrasonic systems to measure metal loss.

This paper provides an overview of special ultrasonic pigging systems and methods. Conventional cable-operated ultrasonic field-proven tools for distances up to 2000m are described, as well as those using long glass-fibre cables up to 6000m in length.

Such tools can be propelled either by reversible wheel-driven crawlers, or by differential pressure, as applied for self-contained intelligent pig propulsion. Self-contained liquid-propelled intelligent pigs are used for on-stream inspection of pipelines; a field-tested system (RPIT) to inspect riser pipes is also described.

INTRODUCTION

Long-distance pipelines are often equipped with launch and receive traps to operate cleaning pigs; most of these traps are long enough also to handle intelligent pigs. Propulsion of such is by the pumped liquid.

Short pipelines, most of the time, are not provided with traps; if such lines are on land, and local excavation is possible, spot checks may be sufficient to ensure their integrity.

For short offshore pipelines, which are often weight-coated with concrete and buried, inspection from the outside is impractical, and is prohibited by the costs involved. In this case, inspection from the inside seems more practical; this also can provide information over the full length, and not just as spot checks. A typical example is the off-loading line illustrated in Fig.1.

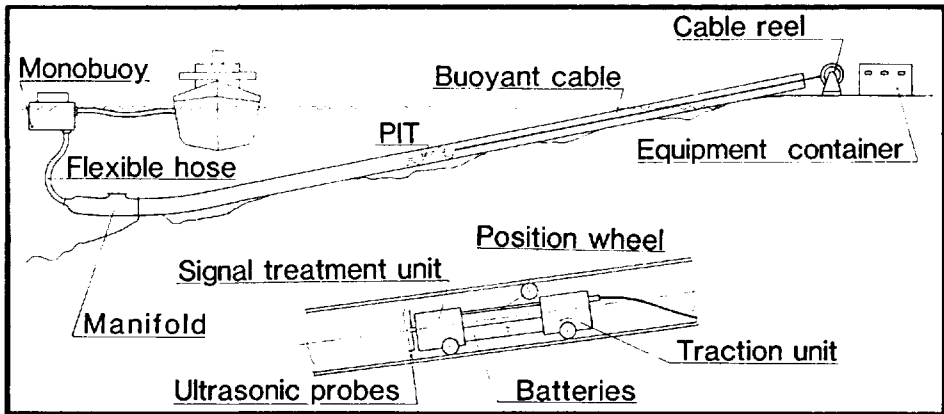


Fig.1. Layout of the off-loading line and PIT.

These lines are used to connect tankers at some distance from the shore to an onshore terminal, and are often found at shallow locations or where extreme tide conditions exist. Lengths up to several kilometres are common.

Only very few of these off-loading lines have launch and receive traps for cleaning pigs; such traps are far too short to accommodate intelligent pigs.

Moreover, at the offshore end of the off-loading line, there often is a manifold of reduced diameter, to which the flexible hoses are connected. As a consequence, any inspection vehicle would have to enter from the land and reverse at the manifold. Most intelligent pigs, however, are not reversible, due to the design of their propulsion cups, and in any case, two-way pumping facilities do not exist at off-loading line locations.

Usually the pumps of the ship are the only pumps available for off-loading lines, although for loading lines there are of course pumps on the land. In that case, reverse pumping could be considered but, as explained above, most intelligent pigs are not reversible.

A few other considerations directed the solution ultimately chosen by RTD. At the time, in the early 1980s, when the first need to inspect an off-loading line arose, even the best existing intelligent flux pigs (ultrasonic pigs did not exist then) were not quantitative enough to justify their offshore application [1]. Also prohibitive was the fact that flux pigs require a relatively-high minimum speed to operate properly. This high speed in itself creates a high risk when the pig, with its large mass, has to be stopped before entering and damaging the manifold. The approximate location of the pig could only be indicated by the amount of liquid pumped, which is far too inaccurate.

Last but not least, the risk of an intelligent pig getting stuck in an off-loading line was considered too great. These lines are often old, sometimes with mitre bends, dents or other unknown obstructions or features. To imagine an obstacle without a rescue line in what is often a "life line" for a plant or refinery was alone reason enough for operators not to apply intelligent pigs to off-loading lines.

It is for all the above-mentioned reasons that RTD worked on a solution, and decided to construct cable-operated ultrasonic pigs. In our solution, as Fig.1 shows, we use a motor-driven crawler. This self-propelled unit makes the operation independent of pumping facilities.

The umbilical for transmission of signals to and from the inspection crawler is reinforced for rescue purposes. An array of ultrasonic probes is mounted at the front end of the inspection tool.

To deploy the tool, the pipeline has to be opened for several metres to attach a simple open launch tray; apart from power supply and hoisting equipment, no other facilities are needed. On-line presentation of results and full control over speed and direction makes the pipeline inspection tool (PIT) very attractive to pipeline owners.

To date, eight successful world-wide applications have proved the viability of this concept.

THE ULTRASONIC STAND-OFF METHOD

The most suitable method of quantifying internal and external corrosion is the stand-off technique as illustrated in Fig.2. A circular array of transducers is located at some distance from the inner pipe wall, and the liquid in the pipe, usually oil or water, acts as the essential acoustic couplant. In this way both the distance from the transducer to the pipe wall as well as the pipe wall thickness can be measured. These readings can be undertaken simultaneously, and with an accuracy of far better than 1mm.

To obtain a fine grid of data, a small axial sampling interval of a few millimetres is usually applied, while for circumferential coverage, a large number of transducers are used; the size of the corrosion pits that can be detected and quantified will depend on the type and number of transducers employed.

Not only is the stand-off technique as shown in Fig.2 well-suited for the measurement of internal corrosion (i.e. profile), but the array of transducers is several centimetres away from the pipe, making the tool less vulnerable to damage. This allows a relatively-simple form of transducer suspension.

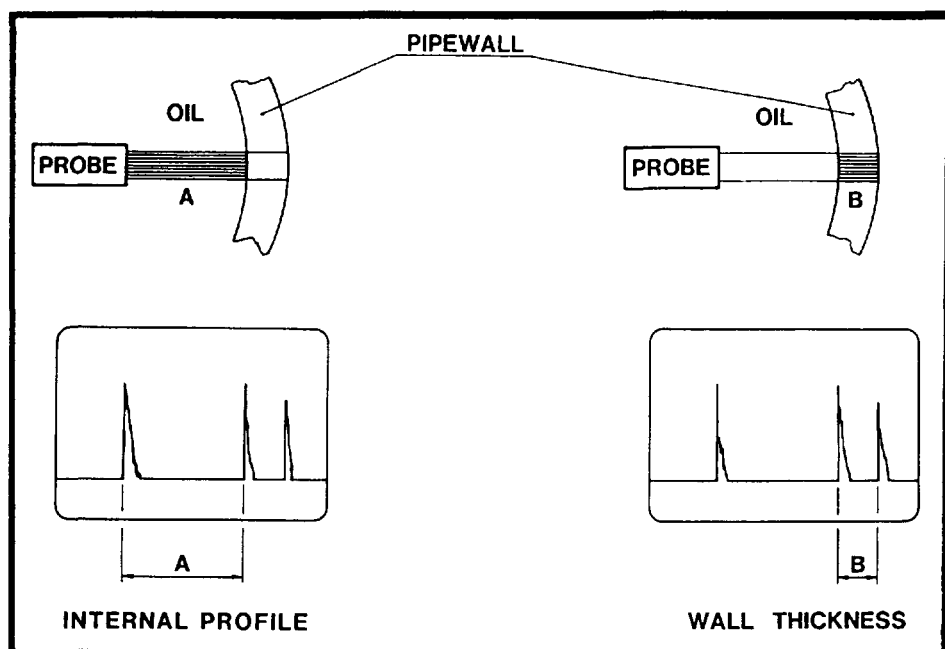


Fig.2. Ultrasonic stand-off method

ULTRASONIC PIPELINE INSPECTION TOOLS

Cable-operated inspection tools

1. The RTD PIT 2000

To inspect almost-straight off-loading pipelines of restricted length, the cable-controlled pipeline inspection tool (PIT) was introduced. Fig.1 shows an overview of the application and the tool itself in more detail. At present with the PIT, a length of up to 2000m of pipeline can be inspected to detect, locate and quantify depth of internal and external corrosion, and measure the remaining wall thickness in corroded areas. The stand-off method is applied as illustrated in Fig.2. The PIT applies 24 ultrasonic transducers (see Fig.3), which can either be distributed freely around the circumference, or densely staggered, on any sector of a pipe (see Fig.4).

Results are instantly presented, as well as being tape recorded for later retrieval and analysis. The tool is launched and operated from an open pipe

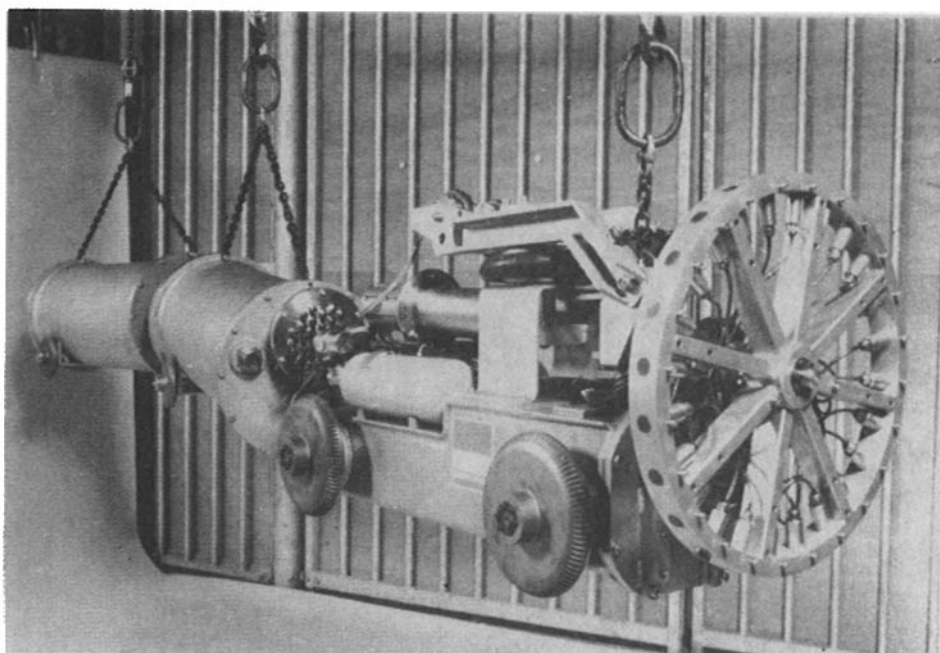


Fig.3. Probes distributed around the pig circumference.

end; all the electronics are installed in a container at the shore, equipped as a control room, from where the direction and speed of the PIT can be controlled. As the PIT is wheel driven, it does not disturb the internal pipe condition. The tool requires oil or (sea) water in the pipeline.

Fig.5 shows the single-body PIT which can negotiate 3D bends for diameters over 30in; the cable on the reel is shown in the background. Fig.6 shows the newest PIT, designed to be suitable for pipelines of 20-in diameter and over. In the background the associated equipment is shown; at the left is the multi-channel (32) ultrasonic instrument, magnetic tape recorder (below), and the paper-chart recorder and control box are at the top right hand side. To allow passage of 3D bends or mitres, the PIT consists of three articulated units connected by universal joints; its flexibility is shown in Fig.7. The tools available are suitable for inspection of pipelines with diameters from 20-48in. Until now, they have been successfully applied in North America, Europe and the Far East for diameters between 26 and 42in. To inspect off-loading pipelines with lengths over 2000m, the tool can be deployed from both ends; this was done in Italy, where one section of the pipeline was inspected from the landfall as illustrated in Fig.8, with the second

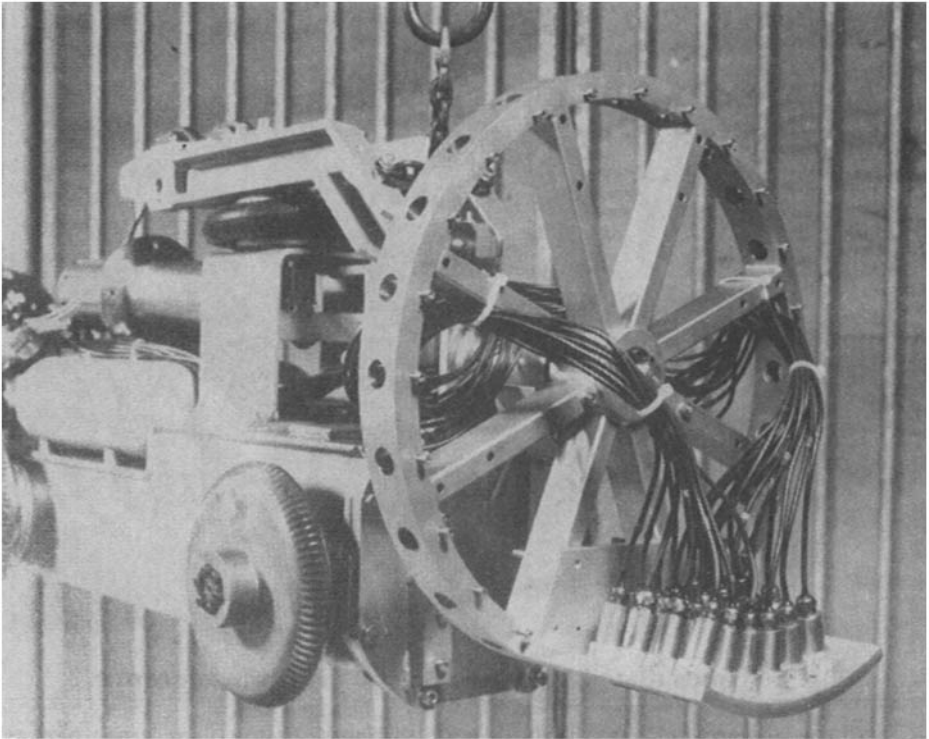


Fig.4. Probes staggered to provide full-sector coverage.

section being inspected from the sea as shown in Figs 9 and 10. In all cases, detachable spoolpieces or launch traps were used to deploy the PIT.

2. The RTD PIT 6000

In order to inspect long off-loading pipelines in one run, preferably from the shore, the PIT 6000 has been designed and is under construction. Basically it uses the same design and construction as the PIT 2000, although as it is almost impossible to increase the length of the 2000-m long conventional cable, it was decided to replace all the copper signal wires in the "galvanic" cable by glass-fibre technology. Experiments have shown that signal transmission for distances over 15,000m is feasible.

For signal transmission, the new cable consist of only a few glass fibres, and is reinforced with aramide fibres to provide a tensile strength of 5000kg. The cable, including a low-friction outer coating, has less than half the diameter

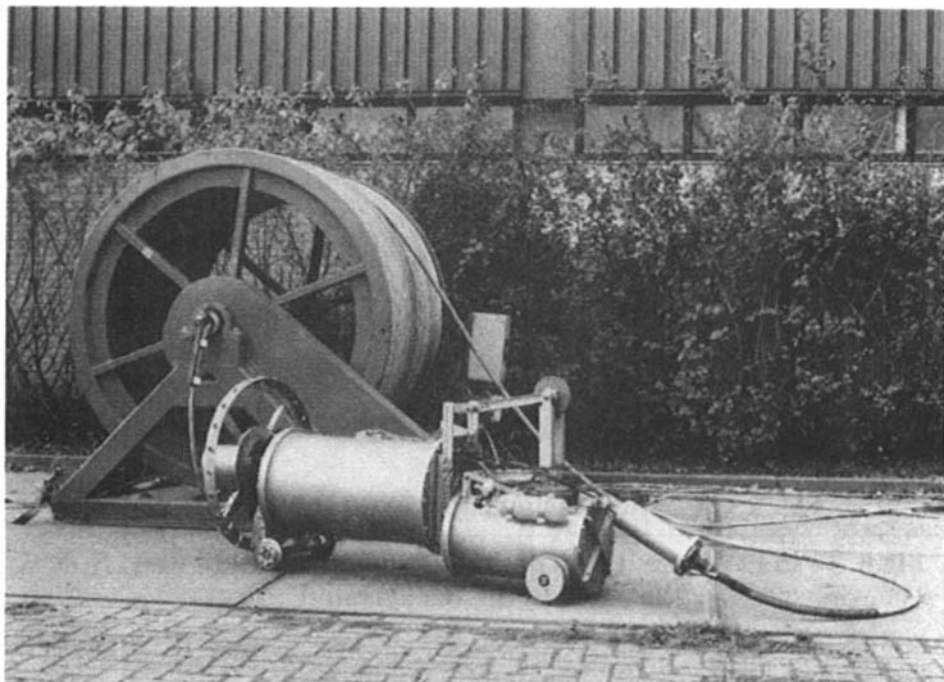
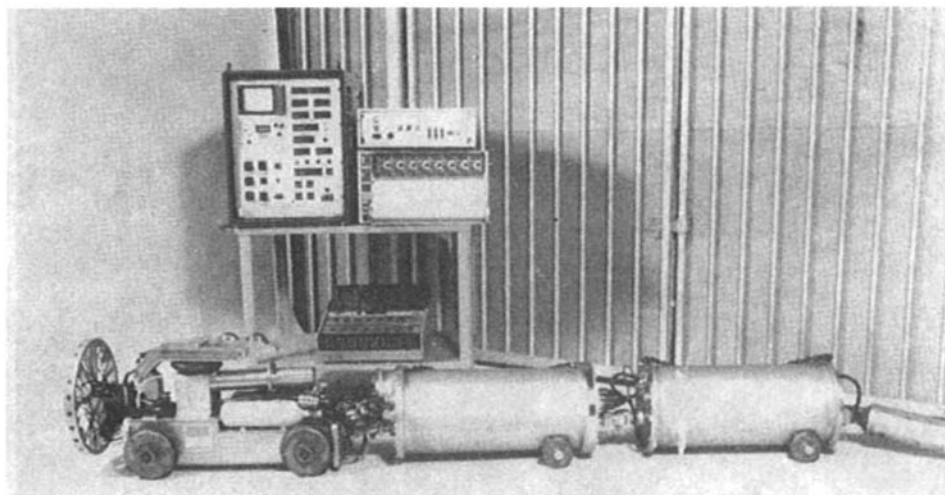


Fig.5. Single-body 30-in PIT with cable reel.

Fig.6. 20-in PIT and electronic equipment.



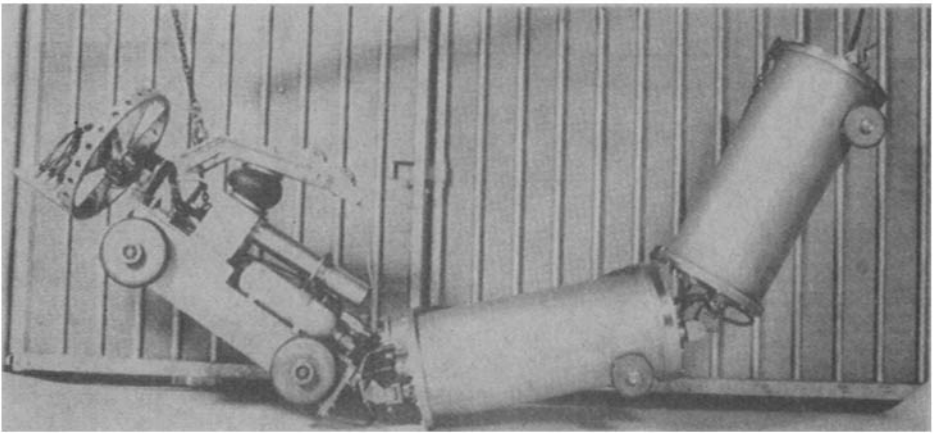
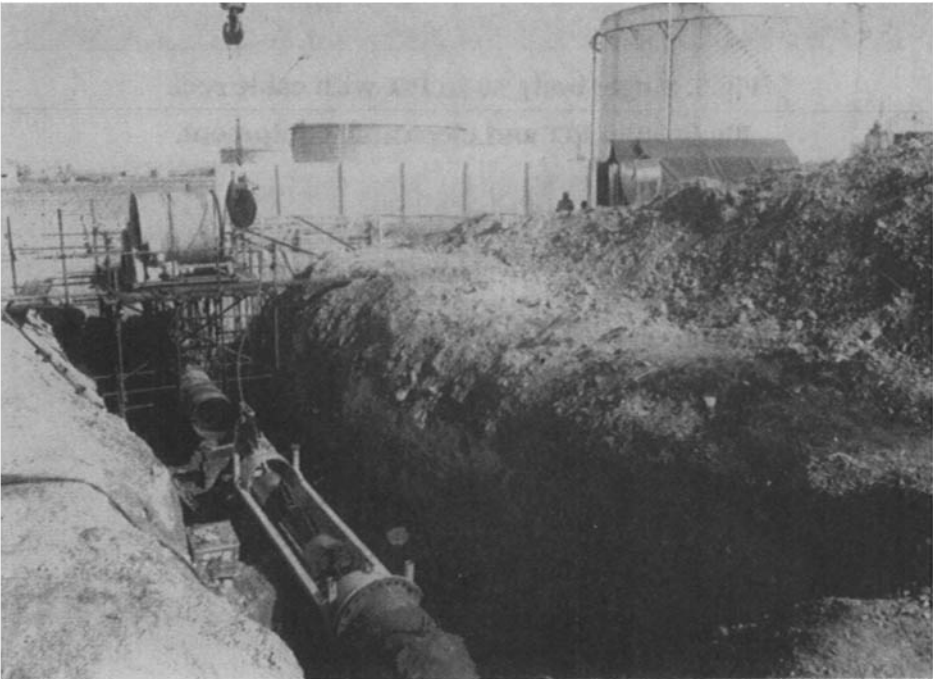


Fig.7. The bend-passing capacity of the 20-in PIT.

Fig.8. 30-in PIT launch trap at the landfall at Taranto, Italy. Note the cable in the background.



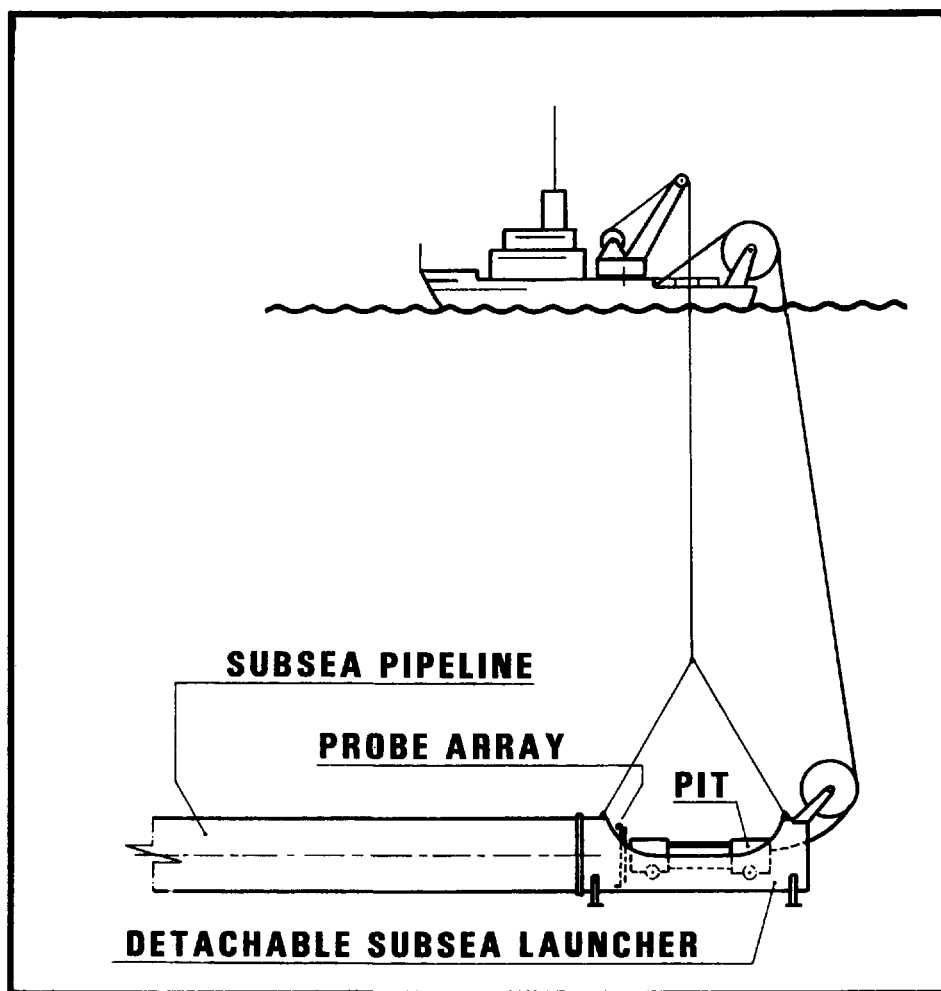


Fig.9. Subsea PIT deployment.

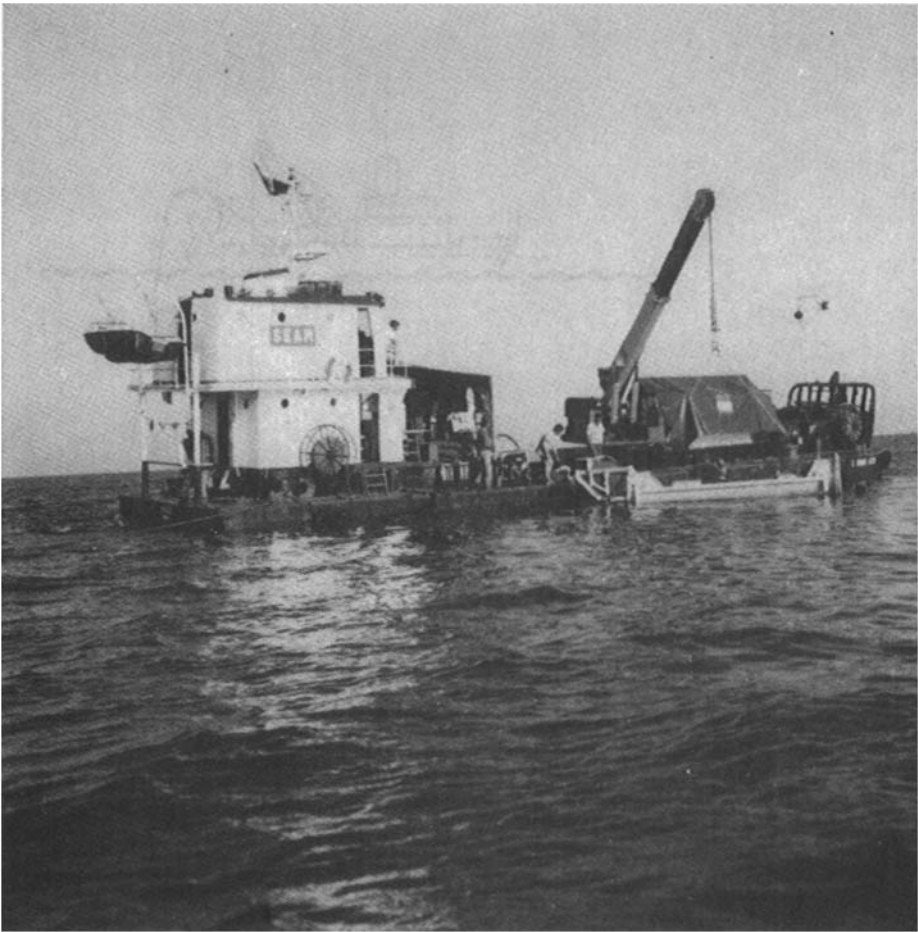


Fig.10. PIT prior to lowering into the subsea manifold at Taranto.

of the conventional cable, and the same reel as used for the 2000-m conventional cable can store the 6000-m optical cable. The reel will be equipped with optical rotary joints for uninterrupted rotation.

The PIT 6000, to be completed in the second half of 1991, will be suitable for inspecting pipelines from 16in diameter. The tool will be capable of passing both 3D and mitred bends, and the number of ultrasonic probes has been increased to 32, in order to provide more circumferential coverage. Once the PIT 6000 has been introduced, expensive offshore deployment will no longer be necessary for pipelines with lengths up to 6000m.

3. Stripper PIT testing

For relatively-large pipe diameters (at present 16in), wheel-driven inspection tools such as the various PITs described are attractive; this technology cannot be used for small diameters.

To propel such tools with cables over long distances, up to 6000m, as well as through bends, high pulling forces are required which cannot be generated by small crawlers. Therefore, the stripper technique has been developed, as illustrated in Fig.11. The measuring module consists of the ultrasonic transducers and multiplexer, and thus can be quite small, and standard components allow the construction of a transducer module suitable for a 6-in pipe diameter, which can also pass 10-D bends. A study has shown that with some additional design effort, a 4-in unit can also be built.

The transducer module is, as for self-contained pigs, propelled by differential pressure over its propulsion discs. To retrieve the tool, the pressure difference has to be reversed. For proper sealing of the cable at the launch/retrieve end of the pipe, a special closure head has to be installed in which a feed-through (e.g. stripper) has been provided. This stripper contains an air-pressure controlled flexible seal to provide the proper balance between sealing and cable friction. This technique was successfully applied in a 10-in

Fig.11. The ultrasonic tool using the stripper concept.

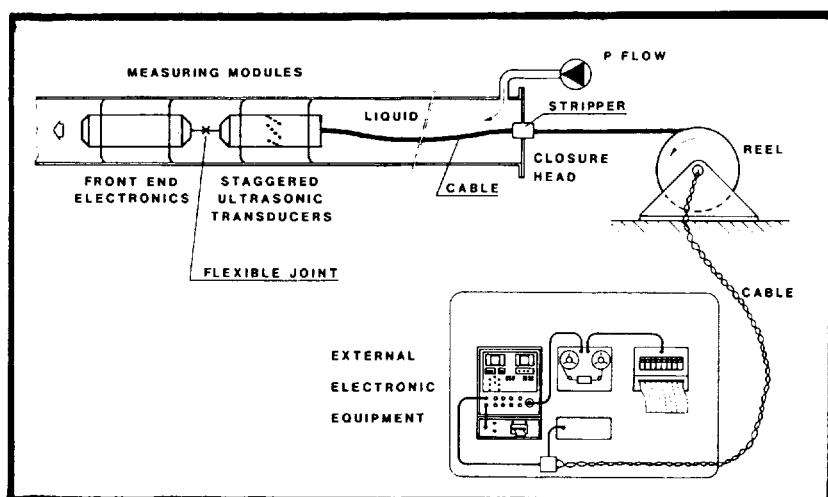




Fig.12. The stripper technique being used in the 10-in test loop.

pipeline as shown in Fig.12. The system proved its capabilities over the full length of the pipe (400m) and several 3D bends (up to 360°).

We assume that the current cable length (2000m) is the only range limit for this technique when applied in an almost-straight pipeline. Probably the combination of bends and cable length sets the practical limits, and this has to be investigated further. An 8-in tool (see Fig.13) has recently been completed for a job in 1991. Fig.14 shows this tool, including the motor-driven winch.

Self-contained ultrasonic tools

4. The RTD RPIT

In order to inspect an oil riser on-stream, RTD and Shell mutually decided to build a fluid-propelled ultrasonic pig using the stand-off method, as shown in Fig.2; Fig.15 shows the schematic lay-out of the consequent riser-pipe inspection tool (RPIT) which was built to the following design specifications:

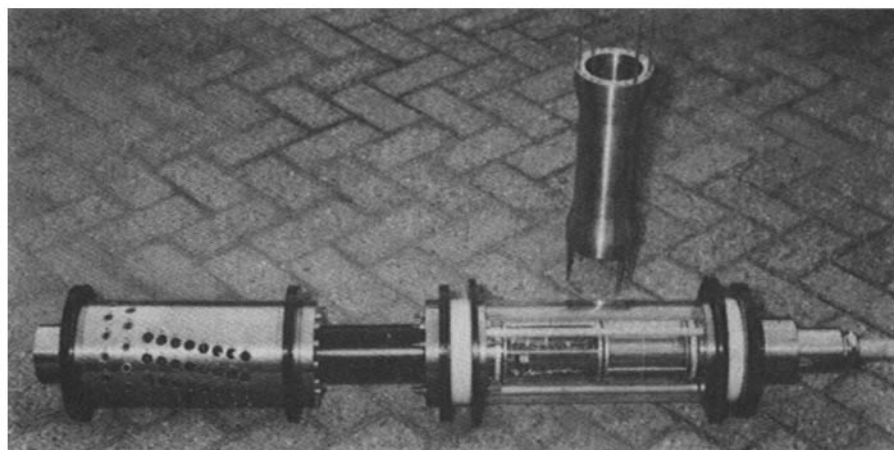
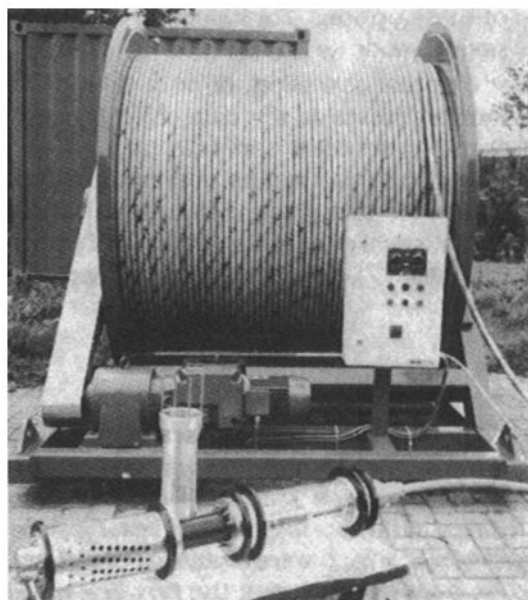


Fig.13. 8-inch stripper PIT with 2,000m of cable on a motor-controlled reel.

Fig.14. 8-in stripper PIT with 2,000m of cable on a motor-controlled reel.



Pipeline Pigging Technology

overall length of 16-in tool:	2.45m maximum
weight:	less than 200kg
maximum measuring speed:	4m/sec
pressure:	150bar
temperature:	5-60°C
measuring range:	300m (without data reduction)
travelling distance:	100km
wall thickness range:	up to 40mm
accuracy of remaining wall thickness measurement:	±1mm
corrosion detection:	internal and external
circumferential coverage:	40%
axial measurement interval:	2.5mm

The tool is also capable of passing 3D 90° bends, full-bore T-joints and valves; 10% symmetric and 15% asymmetric diameter reductions can also be negotiated. The system has been designed to provide a field report of results within 1 hour of retrieval of the tool.

In addition, the RPIT is bi-directional; propulsion disc design provides by-pass of fluid if this is necessary in the unlikely event that the tool becomes stuck.

The RPIT can be started by pressure, time, distance or bench-marker, or any combination of these options. For a delayed start, it travels in a safe and dormant, energy-saving mode to the section of interest in order either to measure internal or external corrosion, or both simultaneously.

The on-board memory stores all the data collected. After retrieval of the tool, a powerful portable desk-top computer is used to process the data; Fig. 16 shows an example of the results obtained. In practice, colours are applied to enhance and identify thickness ranges. Results can also be presented in numerical, statistical or graphic modes for further data analysis. The 16-in RPIT as shown in Fig. 17 has been extensively tested and validated[2] in Shell's 16-in test loop.

5. RPIT field tests

The 16-in and 20-in RPIT have been used twice offshore[3]. The first application was a wire-line field test: pending a field test of the 20-in tool, the opportunity was given to test the 16-in RPIT in open J-tubes on the *Dunlin Alpha* platform, located in the northern North Sea. New flowlines were to be pulled through the J-tubes, which were installed several years ago. High forces were anticipated on the J-tubes during the flowline pulling operation, and therefore a thorough integrity check of the tubes was required.

Cable-operated and self-contained ultrasonic pigs

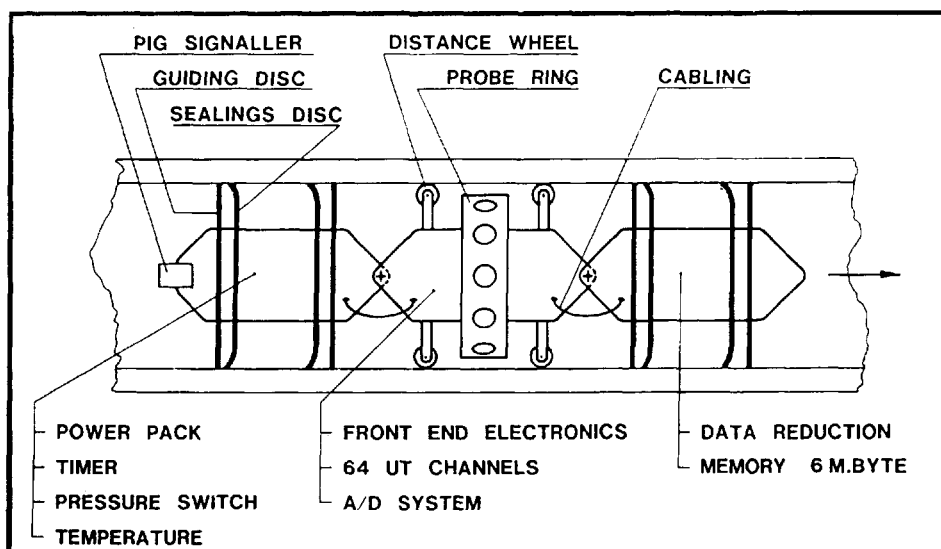


Fig.15. Layout of the riser-pipe inspection tool (RPIT).

The J-tubes are partially embedded in the concrete platform and crude oil storage cells (Fig.18), and are thus inaccessible from the outside for checking the integrity of critical areas. It was established that a slightly-modified RPIT could be used to verify the presence or absence of internal or external corrosion. Since fluid propulsion was excluded, a wire-line operation was the only means available for traversing the RPIT down and up the J-tube. This required a pulling wire through the J-tube, operated from a winch on a vessel, with a second winch and wire operated from the platform; both wires were connected to the RPIT.

By careful synchronous operation of winches, the tool was traversed with an almost constant speed through the J-tubes. Divers stationed at the bottom end of each tube, at 150m below sea level, monitored the entire operation.

In November, 1987, the 20-in RPIT was tested on the *Cormorant* pipeline in the North Sea. This 17-km long oil pipeline connects the *Cormorant North* platform with *Cormorant Alpha*. As shown in Fig.19, *Cormorant North* is a steel platform, while *Alpha* is made of concrete, and it was the intention to inspect the riser of the downstream platform. The oil at *North* has a temperature of 38°C; at *Alpha*, it has dropped to 10°C. For the *Alpha* riser, the RPIT was launched at *North* and propelled by the oil flow with a speed of 1m/sec to *Alpha*. During the travel time of roughly 4 hours, the RPIT was in a dormant condition to save energy and memory. At the correct location, the RPIT was switched on by an external radioactive source which had been placed on the pipe by divers.

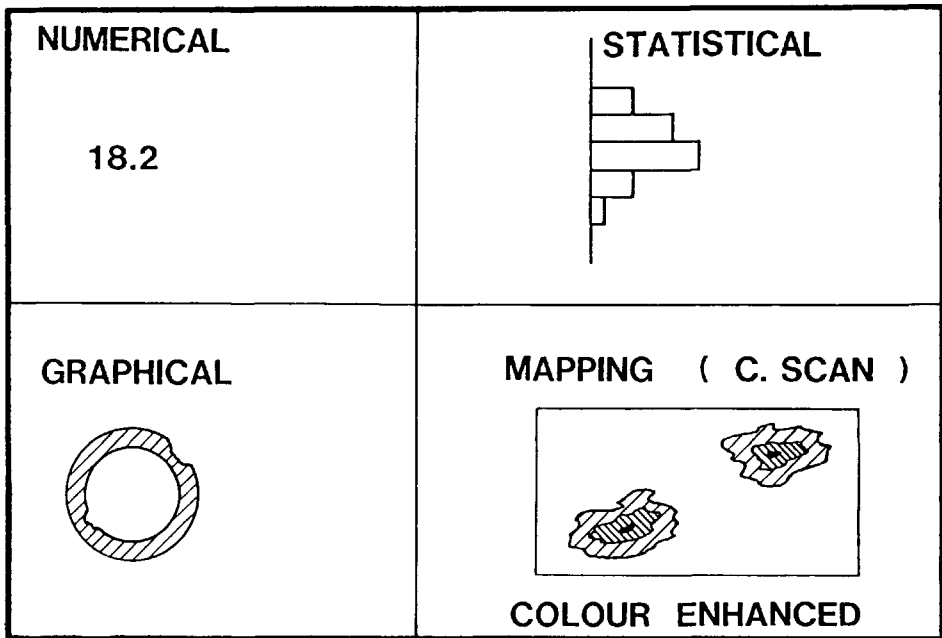
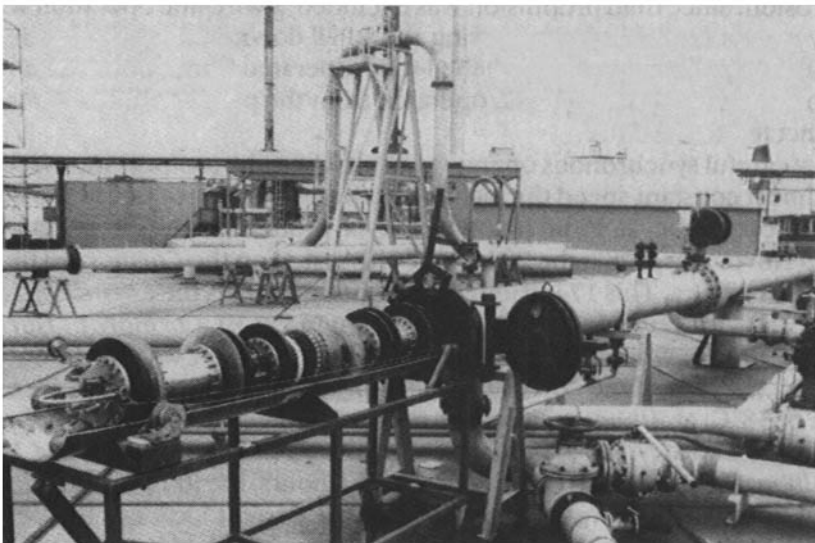


Fig.16. Display modes of the RPIT.

Fig.17. The RPIT at the Shell 16-in test loop.



Cable-operated and self-contained ultrasonic pigs

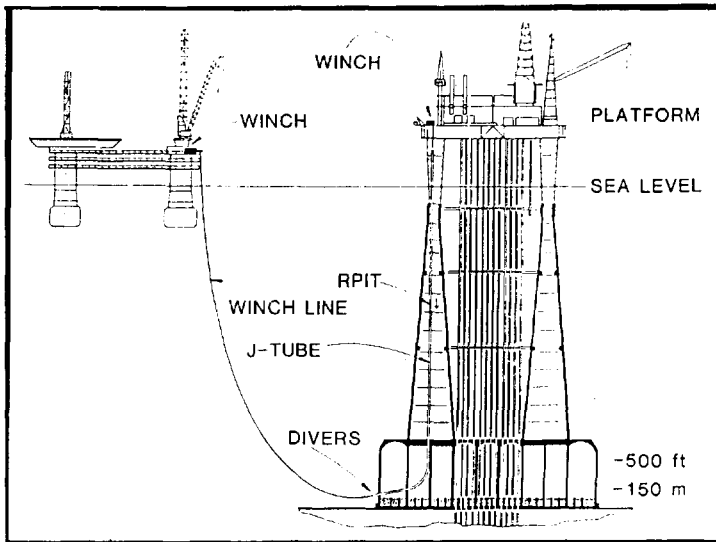
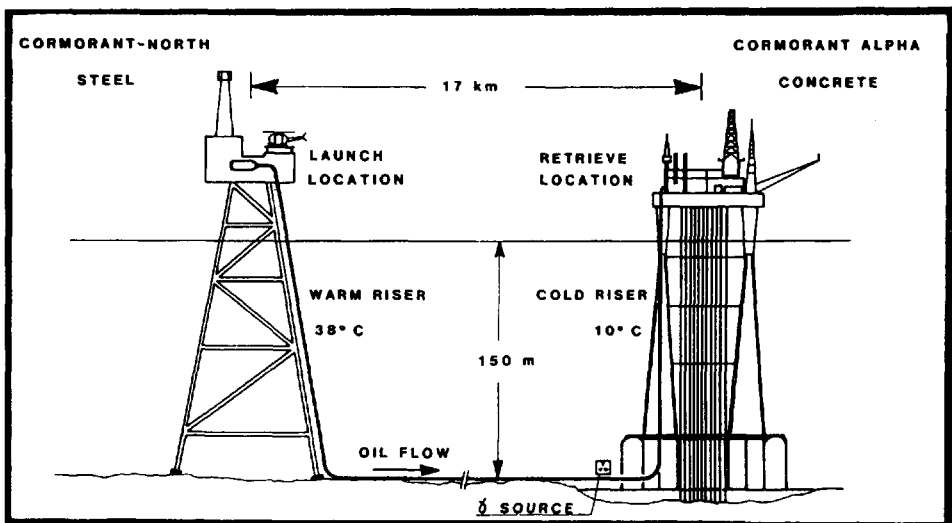


Fig.18. Layout of the wire-line RPIT deployment for the J-tube inspection.

Fig.19 RPIT application on the *Cormorant Alpha* riser.



The operation went smoothly; the RPIT did not stop, passing all pipeline features without problems, and no mechanical damage to the pig occurred. The tool was successfully triggered by the source, and the memory thereafter stored all data from 170m of riser pipe. Values of both stand-off distance for internal profile and wall thickness were recorded. Unfortunately, at many places no readings were obtained. The unexpected presence of free wax in the cold oil (below the cloud point) in the downstream riser caused absorption of the ultrasonic beams, and hence no readings were obtained; however, at locations with no wax, useful data was nevertheless collected[4].

6. Crack detection and sizing

Ultrasonic tools are suitable not only for detection of metal loss; the method is also very well suited to the detection of cracks[5].

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THE ASSESSMENT OF PIPELINE DEFECTS DETECTED DURING PIGGING OPERATIONS

THE ADVENT of high -resolution magnetic-based on-line inspection and monitoring equipment now allows operators to thoroughly assess the integrity of a pipeline. This equipment can find all significant defects in the line, and it is then the operators' responsibility to determine whether these defects require repair.

The significance of many pipeline defects can be assessed using proven, simple analytical methods. These methods can be applied to assess defects detected in-service, or to plan inspection schedules for corroding pipelines.

This paper describes the variety of pipe-wall defects that can be detected during pigging, and summarizes their assessment methods. The incorporation of these methods into condition-monitoring plans is discussed, and finally an overall defect assessment methodology is presented.

INTRODUCTION

Periodic inspection of oil and gas transmission pipelines often reveals corrosion defects. Some 'intelligent' on-line inspection tools can accurately detect, size and locate pipe-body corrosion (Fig.1). Following detection, the significance of these corrosion defects can be assessed using either established analytical methods[1-3], company[4] or national codes[5]. Where corrosion is still active, a further on-line inspection can re-size corroded areas and a corrosion rate can be estimated from the two inspection reports. This rate, combined with further assessment of the significance of the corrosion, can be used to give a long-term assessment of the integrity of a corroding pipeline or, alternatively, allow an operator to instigate improved or alternative methods of controlling corrosion.

Mechanical damage is the major cause of service failures in onshore and offshore pipelines handling petroleum or gas[3]. However, as pipelines age

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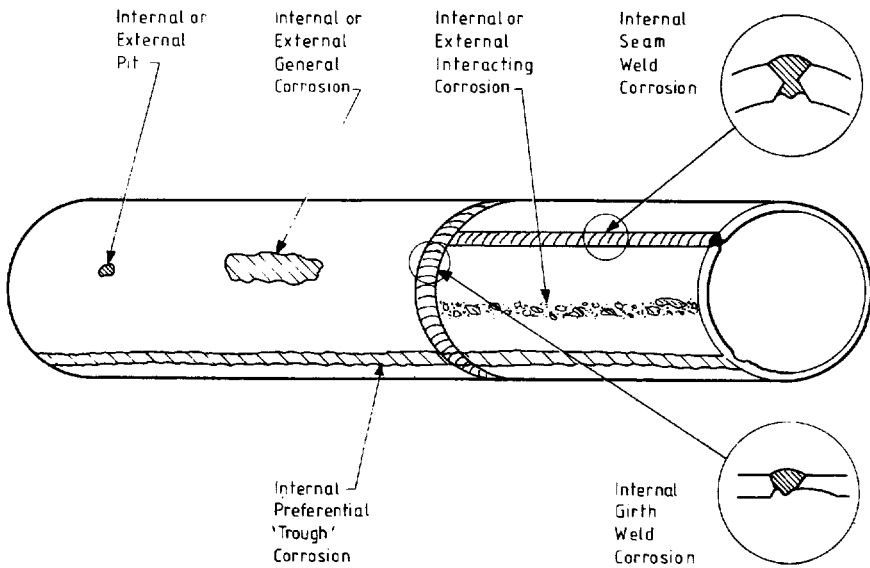
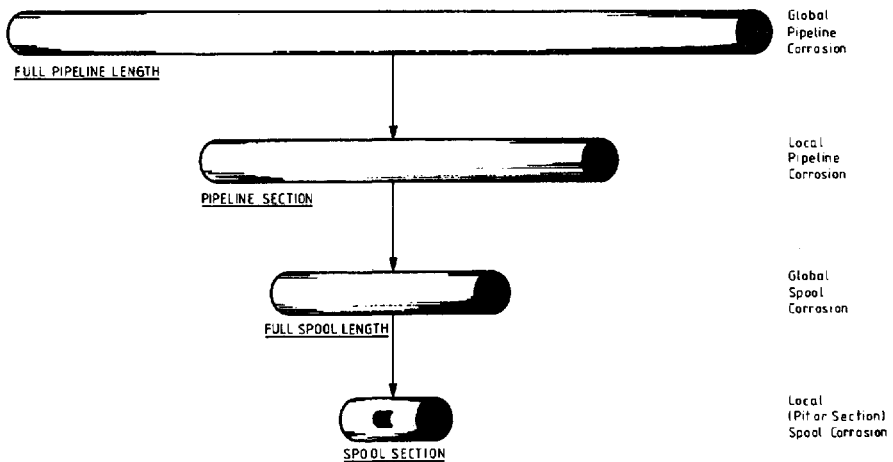


Fig.1. Some types of corrosion found in oil and gas pipelines.

Fig.2. Types of corrosion data available from an OLIV run.



and they are inspected with intelligent pigs, corrosion is proving to be a major problem, causing repair and replacement bills of hundreds of millions of dollars in European[6] and American[7] pipelines.

Therefore, the combination of on-line inspection data with defect-significance calculations is becoming essential as pipelines age and the use of high-resolution intelligent tools becomes more popular. Such tools present a pipeline operator with detailed data, ideal for defect-significance calculations, whereas previous inspection systems could not accurately size or reliably detect defects. The combination of an accurate inspection tool and a reliable defect assessment can avoid expensive repairs which, even for onshore lines, can be in excess of £100,000 per defect.

This paper presents a methodology for the assessment of corrosion in pipelines, with particular reference to on-line inspection of heavily-corroded pipelines. The use of on-line inspection for the condition monitoring of corroding pipelines is discussed and safety factors for use in the assessment methods proposed.

ON-LINE INSPECTION DATA

Introduction

A description of the development of intelligent on-line inspection tools (as exemplified by British Gas) and their capabilities can be found in the literature[8,9]. This section concentrates on the type of data that can be obtained from an on-line inspection, and the analysis of bulk data prior to assessing the significance of the reported corrosion.

Single and repeat runs

On-line inspection tools can give detailed information of a variety of types of corrosion (Fig.1) along an entire pipeline length. The data can be processed to focus attention on sections of the pipeline or individual pits in individual pipeline spools, Fig.2.

The accuracy of some tools is such that readings from a later on-line inspection can be superimposed on those from the early inspection, and corrosion rates obtained for sections of the pipeline, Fig.3(a). Additionally, it is sometimes possible to compare readings in individual spools to check for

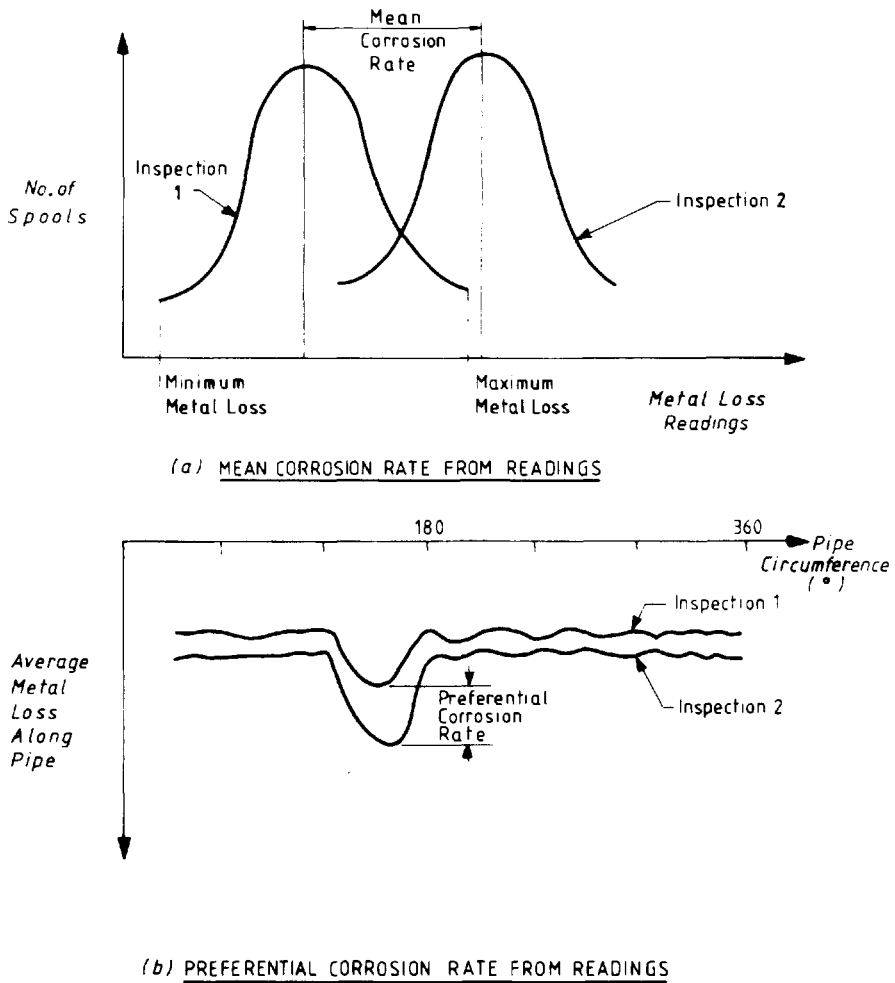


Fig.3. Metal-loss readings from on-line inspections.

preferential corrosion around the pipe circumference, Fig.3(b). The ability of the tools to accurately size corrosion on single or repeat runs means that two types of assessments are possible.

1. Single run: the significance of reported corrosion can be assessed, using the methods given below. After this assessment, the corrosion can be categorized, according to the requirements of repair, e.g. Fig.4. However, where corrosion is still active, the long-term integrity of the line cannot be easily assessed, and repeat inspections are necessary.

2. Repeat runs: the significance of reported corrosion can be assessed and corrosion rates estimated. Where corrosion is still active, the long-term integrity of the line can be evaluated. (Obviously the time between the runs must be sufficient to allow some measurable corrosion to occur.)

Evaluating corrosion rates

The change in wall thickness readings between two inspections of a corroding pipeline gives a corrosion rate, Fig.5. This corrosion rate can then be used to plan future inspections and also to estimate when the pipeline will need either repair, replacement or downrating.

Fig.5 is obviously a simplification, as an inspection report on a corroded pipeline may include many thousands of metal-loss readings. Fig.6 gives an example of the type of wall-thickness data that can be expected.

Application to field data

In a pipeline, each spool can have several hundred metal-loss readings. Therefore, a variety of wall-thickness measurements are available:

- (a) mean metal loss in each spool or the entire pipeline;
- (b) maximum metal loss in each spool or the entire pipeline;
- (c) distribution of maximum and mean metal loss for the entire pipeline;
- (d) distribution of metal loss in a spool.

Following a repeat inspection, changes in all the above will be available. This causes problems in determining corrosion rates and focussing attention on spools which may be corroding at a high rate, particularly if the data are for a long pipeline. It is therefore necessary to somehow 'filter' all the data to obtain information on the worst spools with the highest corrosion rates.

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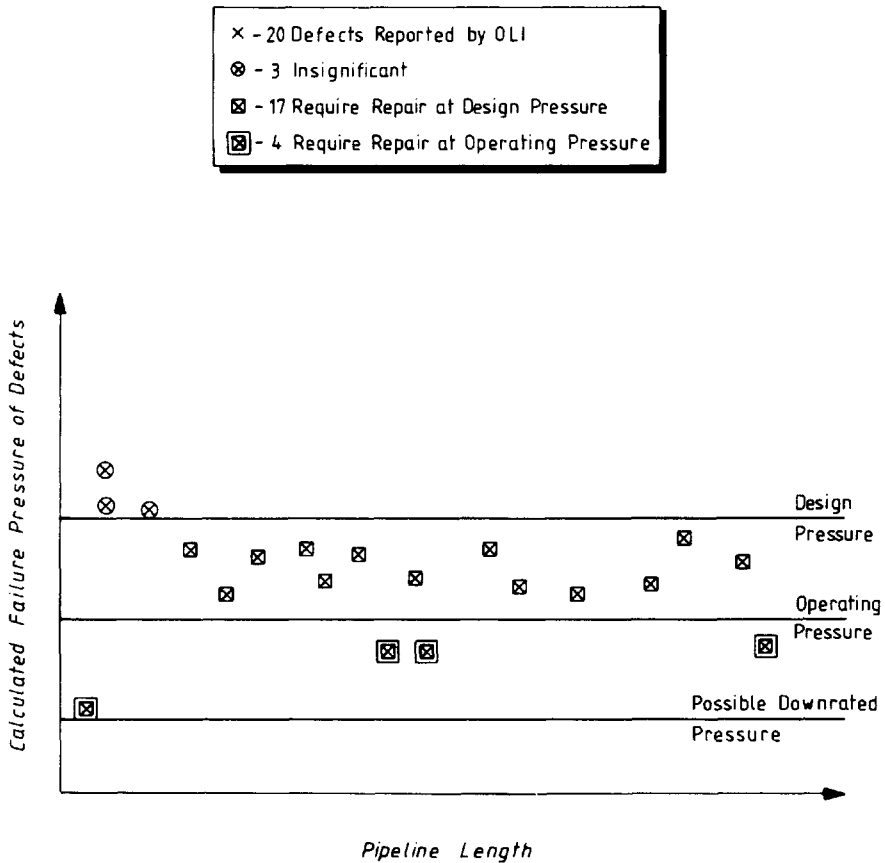


Fig.4. Schematic example of assessment of OLI reported defects.

In effect a 'weak-link' approach is necessary. This approach works on the principle that any failure in a pipeline is unacceptable. Therefore, only the worst area of corrosion, in a pipeline of any length, need be assessed to determine the integrity and future operation of the pipeline. When dealing with bulk data analysis from repeat runs, it is unlikely that a single area of corrosion with a single corrosion rate in a single spool will emerge as the most severe. Instead, it is likely that a group of spools will emerge as the most severe.

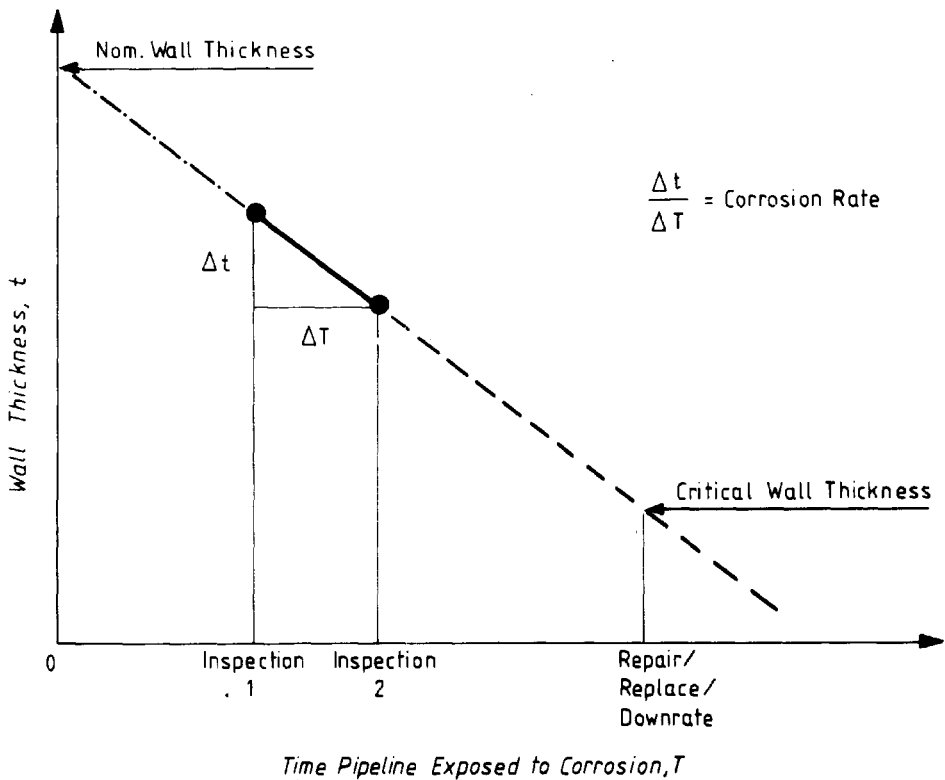


Fig.5. Obtaining corrosion rate from repeat inspections.

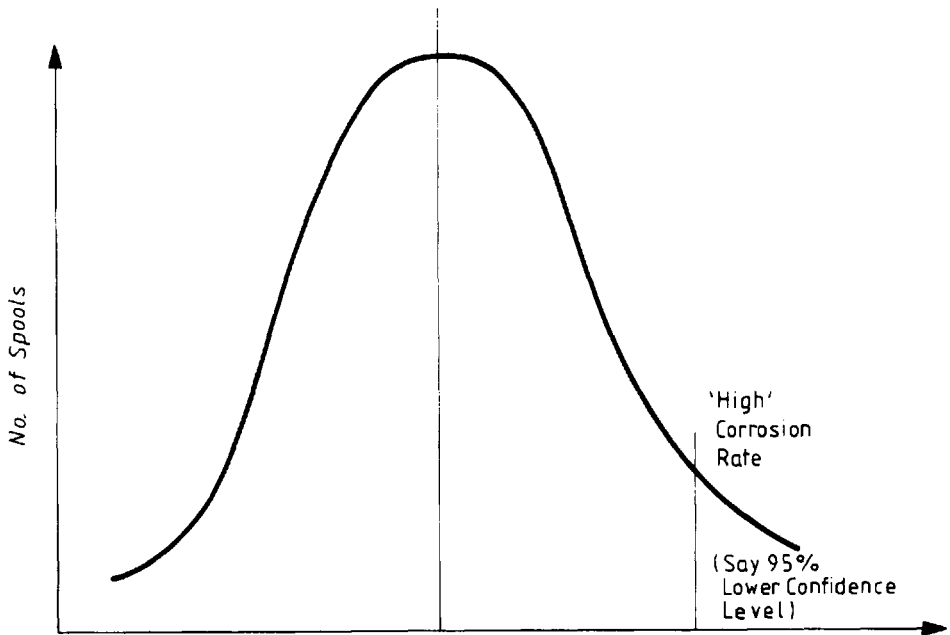
The following procedure is suggested for determining the most severely-corroded spools and corrosion rates from the results of repeat on-line inspection.

Quantifying corrosion rates and severely-corroded spools

Single inspection

The results from a single inspection run are easily evaluated, as spools exhibiting the highest maximum and mean metal loss readings can be readily identified. Prior to a second inspection, spools with 'high' maximum or mean

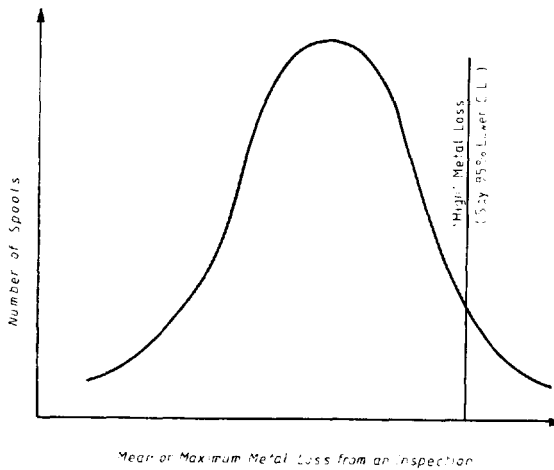
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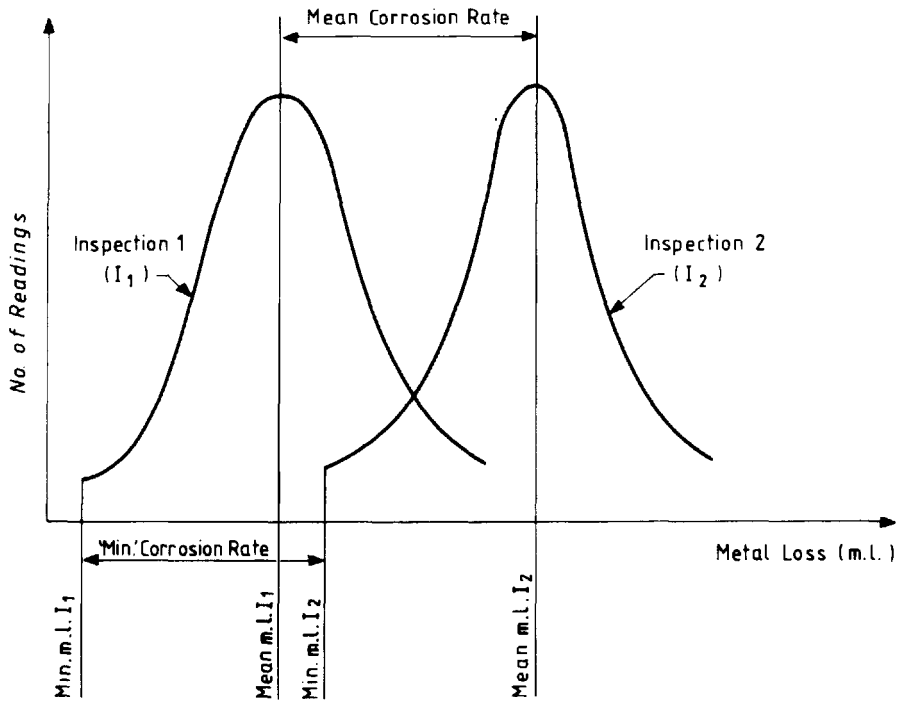
Change in Mean or Maximum Metal Loss in Spools

Fig.6. Metal-loss changes (corrosion rate) between two inspections.

Fig.7. Defining high metal loss.



Assessment of pipeline defects



HIGH RISK SPOOLS :

- Risk A-High Mean Corrosion Rate (Figure 6)
- Risk B-High 'Min' Corrosion Rate (Figure 6)
- Risk C-High Maximum Metal Loss on Inspection 1 (Figure 7)
- Risk D-High Maximum Metal Loss on Inspection 2 (Figure 7)
- Risk E-High Mean Metal Loss on Inspection 1 (Figure 7)
- Risk F-High Mean Metal Loss on Inspection 2 (Figure 7)

PRIORITY RATING

1. Six Risks
2. Four-Five Risks
3. Two - Three Risks
4. One Risk

Fig.8. Distribution of metal-loss readings in a single spool, and priority ratings.

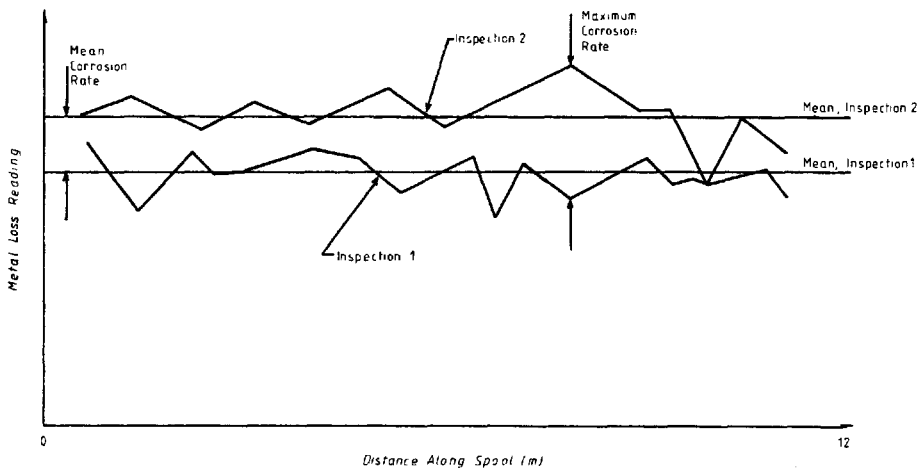


Fig.9. Metal-loss readings along a channel.

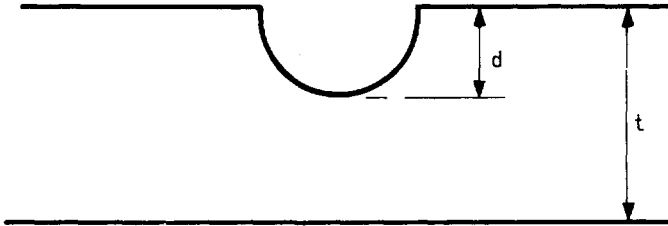
metal loss readings (see Fig.7) can be identified. These spools can then be closely scrutinised during a second run, and the reported corrosion can also be assessed using the methods detailed later.

Repeat inspections

Following a repeat inspection, inspection data will be available for the entire pipeline (e.g. Fig.3(b)) and individual spools, Fig.8; the most severely-corroding spools can be determined using the type of procedure used in Fig.8. Care should be taken in assessing the metal-loss readings from spools; this is because corrosion can be preferential, so that corrosion rates determined from mean metal-loss readings around the circumference of the pipe (Fig.3(b)) and along the axis of the pipe (Fig.9) can be misleading. Similarly, when determining corrosion rates at specific areas of corrosion (i.e. pits), care should be taken in allowing for general wall thickness corrosion as well as pit corrosion, Fig.10.

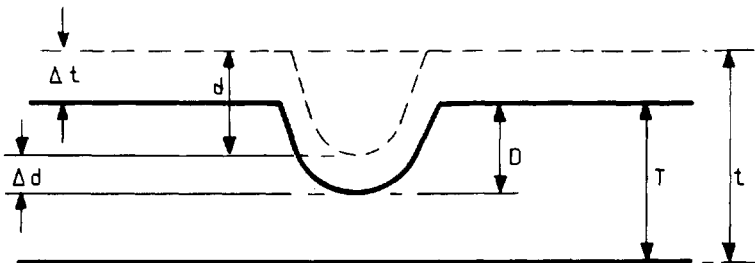
Assessment of pipeline defects

INSPECTION 1



Pipe Wall Corrodes between Inspection 1 and 2

INSPECTION 2



$$\Delta d, \text{Increase in Depth of Pit} = (D + \Delta t) - d$$

Fig.10. Pit model and the effect of corrosion.

CALCULATING THE FAILURE PRESSURE OF CORROSION IN PIPELINES

Structural defects which exceed code tolerances can be assessed using fitness-for-purpose methods. These methods are well-documented[10], and have been used extensively in pipeline welding codes[11]. The ANSI/ASME B31 Code[5] for pressure piping contains a supplement[12] which allows pipeline corrosion to be assessed using fitness-for-purpose methods. These methods are considered acceptable and applicable to pipeline defects.

The failure stress of corrosion in a pipeline can be calculated from[1-3]:

$$\sigma_f = 1.15 \text{ SMYS } (1 - X) \{1 - X (M^{-1})\}^{-1} \quad (1)$$

$$M = 1 + \{0.4 (2c/(Rt)^n)\}^{1/n} \quad (2)$$

where $X = d/t$ or A/A_o
 σ_f = hoop stress at failure
 R = pipe radius
 A = $2c \times t$
 $2c$ = defect length
 t = wall thickness
 A_o = defect area
 d = defect depth
SMYS = specified minimum yield strength

This criterion is nearly 20 years old, but a recent review[13] of failure criteria for defects in pressurized cylinders concluded it was the most accurate. Various *Foltas* factors, M , are used in the literature but they are all very similar, with Eqn(2) the most conservative[13].

The accuracy of this criterion can be evaluated by comparing predicted failure pressures with actual failure pressures of full-scale tests on corroded pipe[2,14]. The predicted failure pressures are dependent on the use of:

- (i) either maximum defect depth (d) or actual defect area (A); and
- (ii) actual yield stress (σ_y) or SMYS in the failure criterion.

The most accurate predictions are obtained using defect area and actual yield stress[3]. The most inaccurate (and most conservative) predictions are obtained using SMYS and maximum defect depth. Using the data in Refs 2 and

14, it is possible to calculate safety factors that, when applied to Eqn(1), will give safe (95% confidence level*) predictions. Ref.3 suggests that a safety factor of 0.97 should be applied to Eqn(1) and recommends the use of SMYS and maximum defect depth.

SAFETY FACTORS ON FAILURE PRESSURES

The end product of a fitness-for-purpose calculation is a failure pressure for a defect. Factors should then be applied to the failure pressure to accommodate uncertainties in the fitness-for-purpose analysis and also in the operation of the pipeline (e.g. surges). A safety-factor philosophy directly related to code requirements can be proposed[3]. Summarizing:

$$\text{maximum operating pressure, } P_o = SM \times SF \times P_f \quad (3)$$

where P_f = predicted failure pressure of corrosion (Eqn(1));
 SM = safety margin related to pipeline codes; and
 SF = safety factor to accommodate errors in failure criteria.

A value of $SF = 0.97$ is recommended to give a 95% confidence level on failure predictions.

SM is obtained by considering the design and hydrotest pressures specified in pipeline codes. Most codes, e.g. IP6[15], have a maximum design pressure of 72% SMYS and a hydrotest pressure in excess of 90% SMYS. If we assume that a defect-free pipeline will fail when the hoop stress reaches flow stress ($\approx 1.15 \times SMYS$)[2], we obtain the following safety margins (Fig.11):

$$\text{hydrotest** safety margin} = 0.72/0.90 = 0.8$$

$$\text{defect-free pipeline safety margin} = 0.72/1.15 = 0.63$$

Thus a new IP6 pipeline will have a safety margin between 0.8 (guaranteed by the hydrotest) and 0.63. This latter defect-free safety margin is optimistic because an operational pipeline, with its fittings, bends, etc., cannot be expected to withstand a stress of 115% SMYS.

* The use of a 95% confidence level (mean minus 2 standard deviations) in failure calculations has been accepted as good practice for many years, with its adoption in BSI PD6493[10], the major defect assessment code. The design curve (in effect the 'fracture' curve) in BSI PD6493 is a 95% lower confidence level on a large fullscale test data base.

** Care should be taken in calculating these margins, as hydrotest and operating stress levels can be based on minimum or nominal wall thickness.

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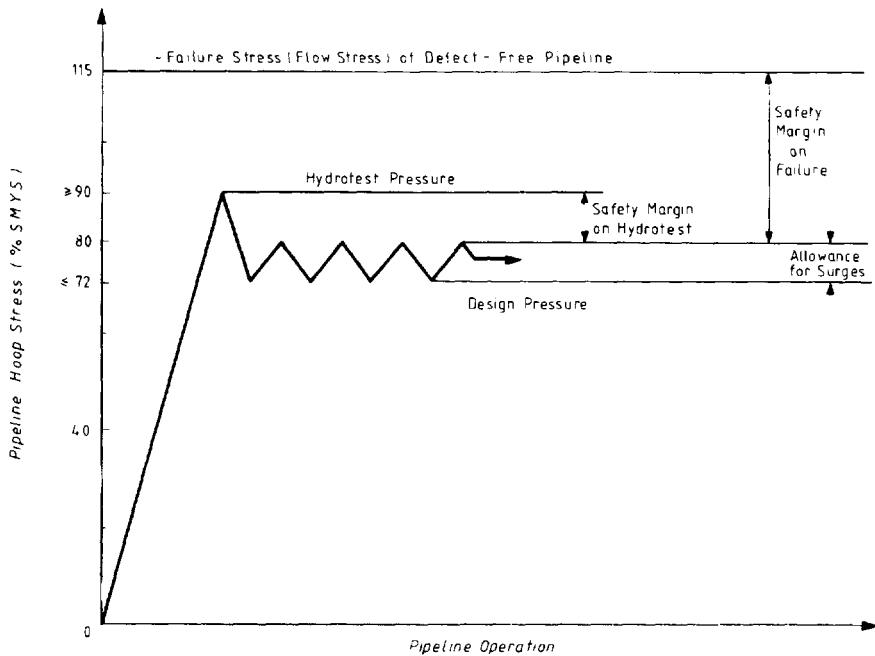


Fig.11. Safety margins in IP6[15] pipeline code.

An intermediate safety margin of 0.72 is obtained by using the SMYS:

$$\text{'SMYS' safety margin} = 0.72/1.00 = 0.72$$

This safety margin is arbitrary and cannot be related to the IP6 code, but it is directly related to a pipeline property, SMYS, and is the margin resulting from a hydrotest to 100% SMYS level. Therefore, three overall safety factors (SM x SF) in Eqn(3) can be proposed:

(IP6) 'Hydrotest'	= 0.8 x 0.97	= 0.78	4(a)
'SMYS'	= 0.72 x 0.97	= 0.70	4(b)
'Defect Free'	= 0.63 x 0.97	= 0.61	4(c)

These safety factors are then applied to Eqns(1) and (2) to obtain a safe operating pressure; Fig.12 presents Eqns(1) and (2) graphically. The above safety factors relate to the assessment methods and relevant codes; they do not take into account detection limits, tolerances, etc.

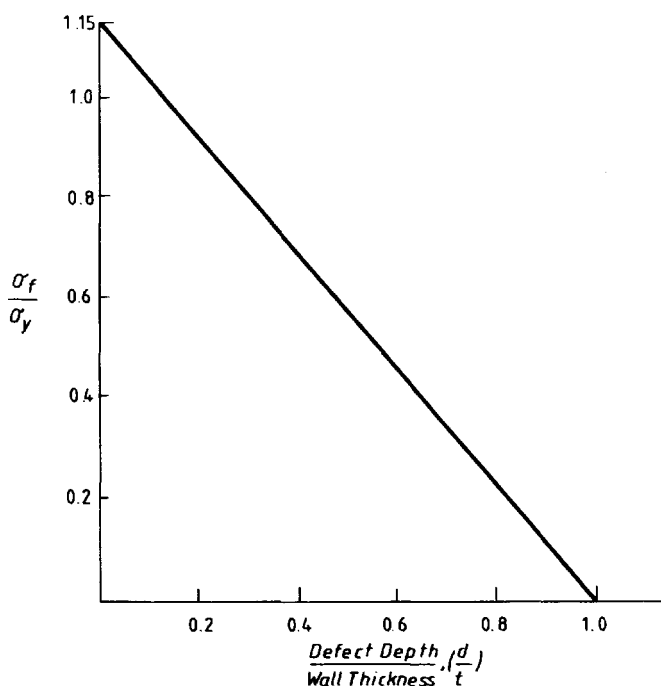
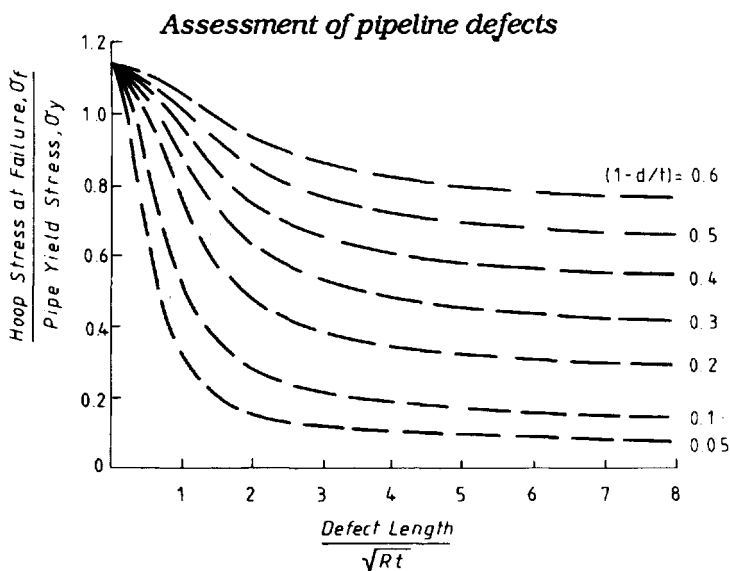


Fig.12(a) (top). Failure of pipe-wall defects in pressurized linepipe[1,2].

Fig.12(b) (bottom). Failure of infinitely-long defects in pressurized linepipe.

A METHODOLOGY

The above sections can be combined to develop a methodology for assessing the significance of corrosion in pipelines. The methodology can be divided into three parts:

1. processing corrosion data;
2. modelling corrosion;
3. deriving acceptable defect curves with safety factors.

Processing corrosion data

Figs 3-10 give methods of obtaining corrosion rates and highlighting suspect spools from on-line inspection data.

For a single on-line inspection, a 'weak link' approach is recommended. This means determining the most severe defect in a pipeline and the significance of this defect governs the pipeline integrity. In practice, a number of defects, of different sizes and shapes, will be reported that are above agreed defect reporting levels. As the failure stress of corrosion is related to both corrosion length and depth, it is necessary to determine the significance of all these defects (e.g. Fig.4).

Repeat inspections may allow an estimate of corrosion rate; Figs 3-6 give methods of determining this rate.

Modelling corrosion

A high-resolution magnetic-based on-line inspection can give a reliable estimate of corrosion size. For a single inspection, the maximum size of the corrosion should be used in setting defect acceptance levels; this means that all defects are conservatively modelled as 'flat-bottomed' (see Eqns(1) and (2)). Additionally, it may be necessary to take account of inspection tool sizing tolerances in the depth and length inputs into Eqns(1) and (2).

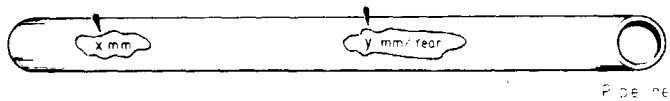
For repeat inspections, it may be necessary to model the corrosion rate as well as the defect size. A variety of models are possible; Fig.13 gives three examples of modelling corrosion and corrosion rate. In practice, it may be necessary to evaluate all such models and take lower bound values. Modelling of pitting corrosion and rates is given in Fig.10.

Assessment of pipeline defects

a) MODEL 1

(a) Maximum Metal Loss

(b) Highest Corrosion Rate Based on Maximum Metal Loss Differences



b) MODEL 2

(a) Maximum Metal Loss

(b) Highest Corrosion Rate Based on Maximum Metal Loss Differences



c) MODEL 3

(b) Average all O.V. Data Along this Axis to Obtain Mean Metal Loss

(a) Determine Most Severely Corroded Area Around Pipe Circumference

Differences in Inspection 1 and Inspection 2 Mean Metal Loss Readings Along this Axis give Corrosion Rate



Fig.13. Modelling of pipe-body corrosion.

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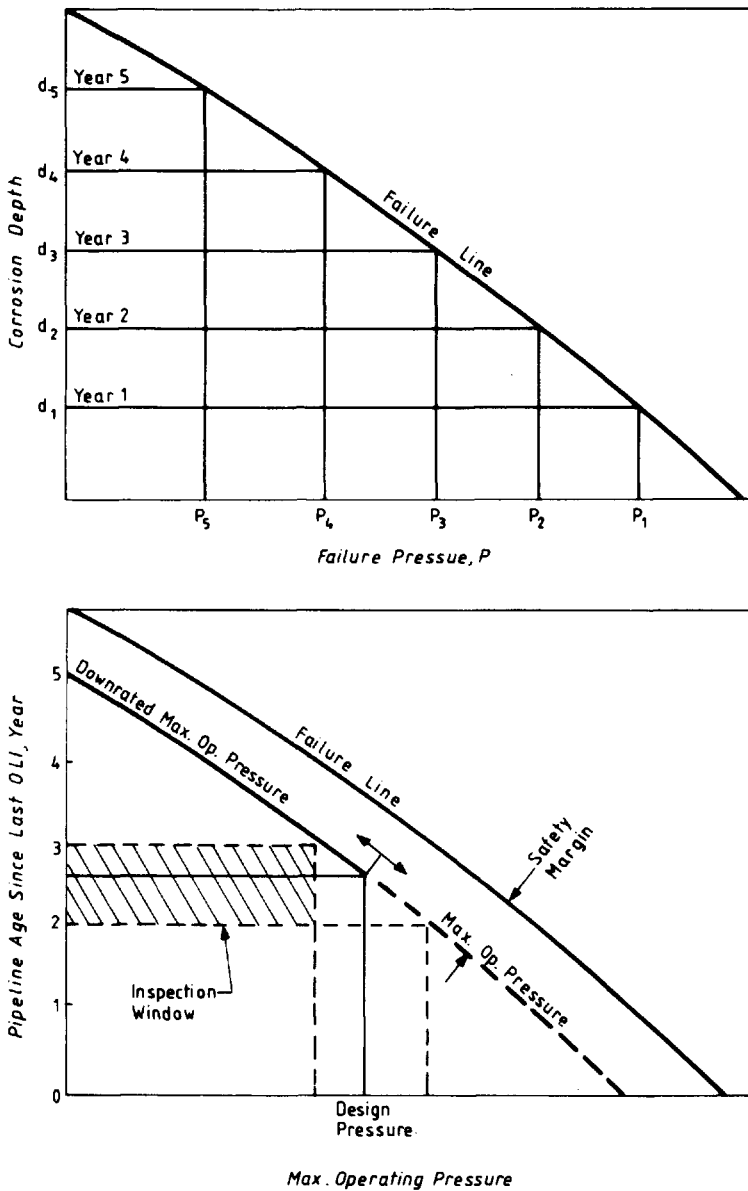


Fig.14(a) (top). Failure pressure of corrosion defect with time.
Fig.14(b) (bottom). Operating pressures and inspection requirements in corroding pipelines.

Assessment of pipeline defects

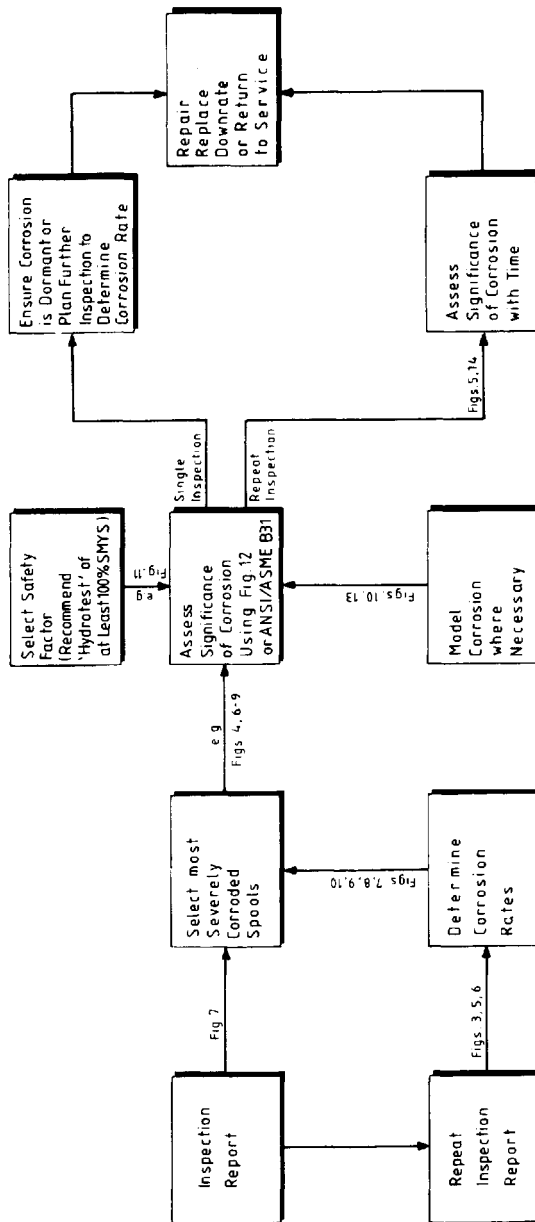


Fig.15 : Defect Assessment Methodology

Fig.15. Defect assessment methodology.

Deriving acceptable defect curves

The equations necessary for deriving acceptable corrosion defect curves are given above (or the acceptance levels in the ANSI/ASME Code[12] can be adopted). The selection of safety factors for use in Eqn(1) will be the responsibility of the pipeline operator, but the hydrotest safety factor has the advantage of being directly related to code and pre-service requirements. In some codes (particularly for oil pipelines) the hydrotest level is relatively low (e.g. IP6[12]), and it may be better to use a higher hydrotest level in deriving a safety margin, e.g. 100% SMYS as used in the ANSI/ASME B31.4 Code[5],[12], to ensure a reasonable safety factor.

Deriving repeat inspection intervals

The acceptable defect curves can be used during repeat inspections. These can be combined with corrosion rate data to predict increases in corrosion depth with time, Fig.14(a). The curves, with safety factors included, can also be used to both predict when any downrating of operating pressure is needed or when it would be necessary to re-inspect the line to avoid downrating, Fig.14(b).

CONCLUDING REMARKS

A defect assessment methodology for corroded pipelines, based on the above sections, can be proposed. Fig.15 summarizes the methodology, and it is recommended that this type of methodology is applied to future assessments of corroded pipelines. It can be applied to pipelines containing limited corrosion or extensive corrosion. However, there are some limitations, and these are listed in Ref.3. For example, the interaction of neighbouring corrosion pits is not well understood. However, the methodology will be applicable to most corrosion types, despite these limitations.

It should be emphasized that a defect assessment is only as good as the defect inspection report. If the report is inaccurate, the defect assessment will be inaccurate. Therefore, a reliable, accurate inspection tool is required if the above methodology is to be applied. These tools can be expensive, but they allow defect assessments which avoid expensive repairs to the pipeline.

ACKNOWLEDGEMENTS

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BI-DIRECTIONAL ULTRASONIC PIGGING: OPERATIONAL EXPERIENCE

HAVING SUCCESSFULLY inspected a 48-in 11-km offshore pipeline using a bi-directionally-travelling ultrasonic inspection pig, NKK has proven its technological ability to provide valid data for efficient, cost-saving maintenance.

INTRODUCTION

The natural environment will be severely affected in the event of a leak from an offshore crude-oil loading pipeline. To prevent such leakage due to corrosion, an inspection of the development of pipeline corrosion by means of an inspection pig is effective. Most offshore loading pipelines are installed between the shore with storage tanks, and the PLEM (pipeline-end manifold) on the sea bottom, permitting connection to a tanker via a flexible rubber hose. At present, however, difficulties are always encountered in carrying out the inspection of offshore pipelines by means of an inspection pig, because the structure of the offshore crude-oil loading line is not suited for installing a launcher or a receiver.

NKK has developed an inspection pig that makes it possible to inspect the state of corrosion of a pipeline by travelling bi-directionally in the line provided there is a sufficiently-large area at the shore end of the line to install a launcher/receiver.

This paper outlines how the inspection of the inside of an offshore pipeline was conducted by a bi-directional ultrasonic inspection pig currently in use in Japan.

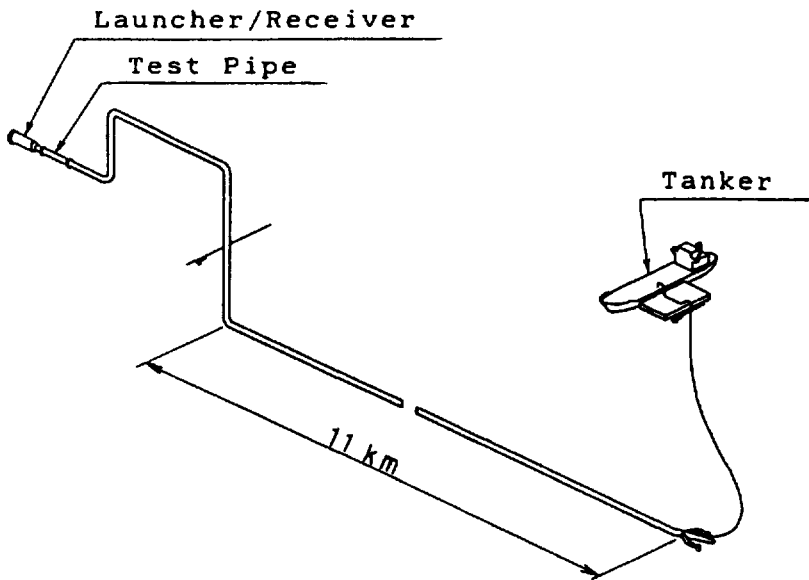


Fig.1. Offshore pipeline overview.

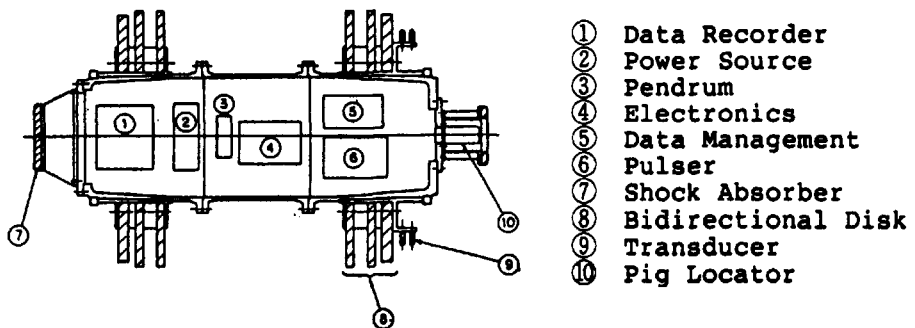


Fig.2. Diagram of the bi-directional ultrasonic pig.

PIPELINE, PIG AND OTHER DETAILS

A 48-in diameter crude-oil loading offshore pipeline with an approximate length of 11km was required to be inspected (see Fig.1).

Pipeline details

Nominal diameters:	42-48in
Fluids:	crude oil, product oil, seawater, fresh water
Fluid pressure:	10 kg/cm ² and less
Fluid temperature:	normal temperature
Bend radius of pipe:	1.5 times pipe diameter

Specification of inspection pig

Type:	ultrasonic
Measuring method:	inspection of inside wall and outside surface for corrosion
Total number of sensors:	240
Travelling method:	bi-directional
Weight:	1,800kg
Overall length:	2.125m

Data analysis system

Inspection data from the designated areas can be regenerated by an on-site data-analysis system. The data regenerated is output to a monitor display in the form of a picture image as if seen from inside the pipeline. Following analysis on the monitor display, data for the whole line is transferred to an engineering work station at the NKK Engineering Centre, where a complete and detailed analysis is conducted, using reporting formats such as tabulating corrosion, and providing a planar view (plane pattern), a longitudinal cross-section, a circumferential cross-section, a contour map, and a colour planar view. Fig.3 shows the data-analysis system.

Reporting formats

With an internal, natural corrosion sample patched on the NKK test loop, the detection capability of the bi-directional ultrasonic inspection pig has

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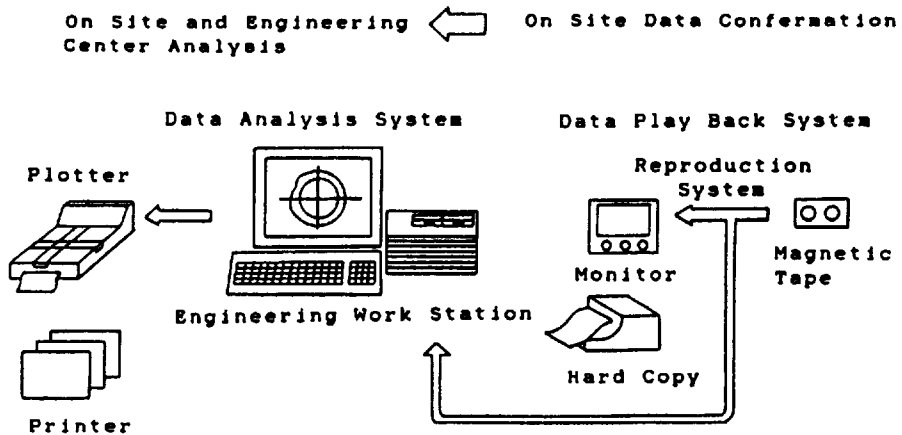


Fig.3. Outline of the data-analysis system.

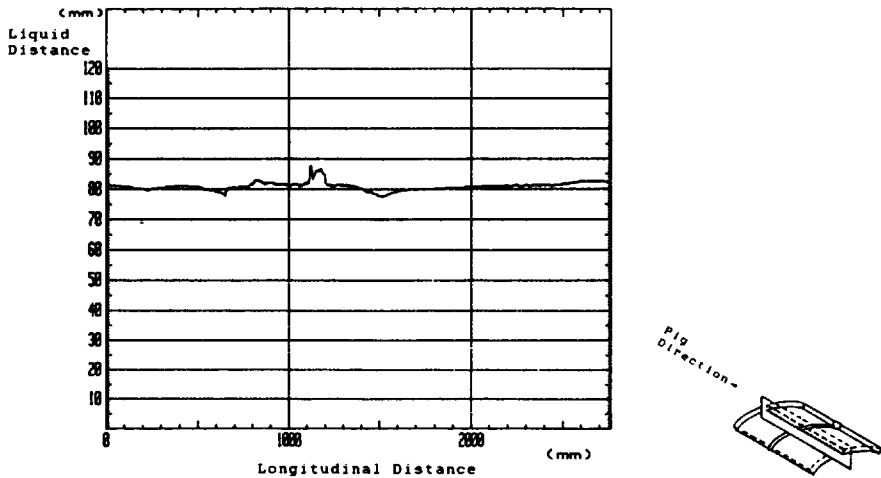


Fig.4. Longitudinal cross-section.

Bi-directional ultrasonic pigging

been confirmed, as shown in photos 1 and 2. Figs 4-6 show the inspection results using the internal, natural corrosion sample (shown in Photo 3, which was 6mm deep, 410mm circumference and 20mm long) which was generated on the girth weld.

Overview of inspection work

Inspection period: September, 1988.

Pigging operation: A launcher/receiver was temporarily set at the shore end of the pipeline. On the PLEM, a tanker was moored and a flexible hose connected to the tanker from the PLEM.

Initially, the pig was launched into the pipeline from the shore to the PLEM, propelled by seawater injected from a brine pump installed on the shore; the seawater was drained into the oil hold of the tanker. Upon arrival at the PLEM, the pig was returned to the shore by means of a cargo pump mounted on the tanker, and recovered in the launcher/receiver. The seawater was then drained into a crude-oil tank on the shore.

Profile pig: A profile pig with the same outside diameter as that of the inspection pig was provided with an aluminium fin in the equivalent location of the ultrasonic transducer ring. After its passage through the pipeline, the profile pig was examined to investigate any deformation of the fin and the state of disc abrasion; it was confirmed that there was no obstruction to the subsequent safe passage of the inspection pig. Photo 4 shows the bi-directional profile pig.

Ultrasonic inspection pig: Following confirmation by the profile pig that there was no obstruction in the pipeline to the safe passage of the inspection pig, the inspection pig was launched to examine the condition of the inside wall of the pipeline. The travel speed during inspection averaged 0.24m/sec; photo 5 shows the ultrasonic inspection pig.

Site review: Immediately following inspection by the ultrasonic pig, data analysis was undertaken, firstly by analyzing the data from a calibration section (comprising an artificially-corroded test pipe installed downstream of the launcher/receiver), followed by validating the accuracy of the data acquired from the pipeline under observation. Data analysis was conducted and observed on site.

After detailed data analysis, a final report was delivered to the client approximately one month after completion of the pig inspection.

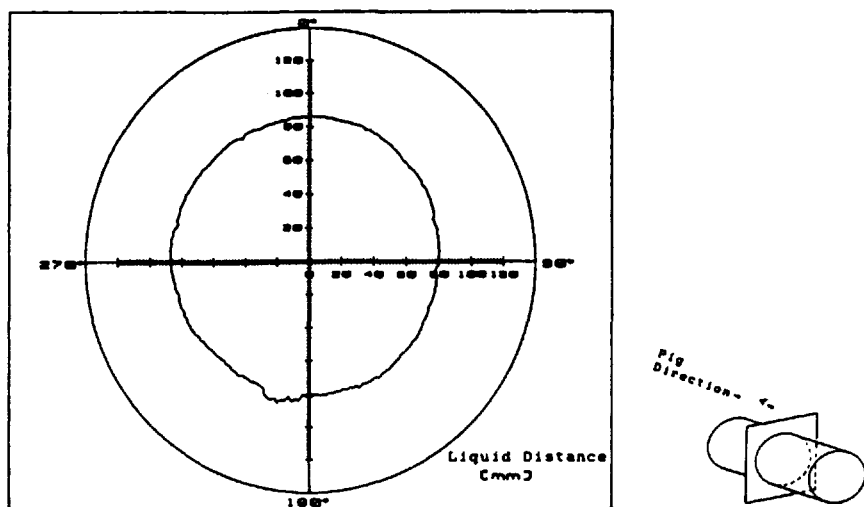


Fig. 5. Circumferential cross-section.

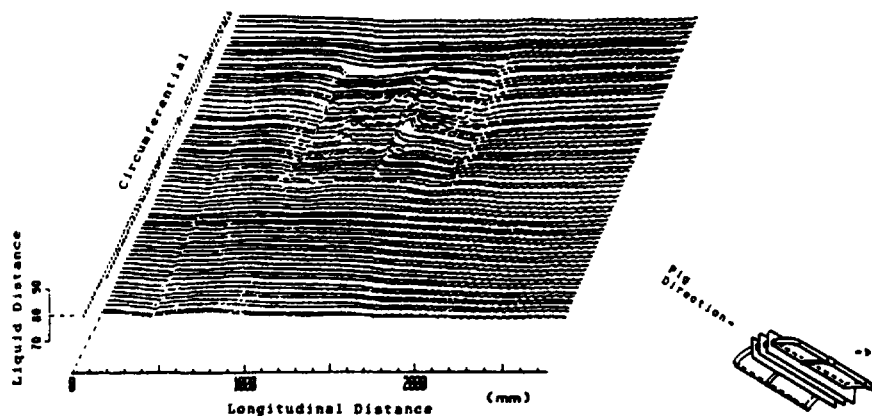


Fig. 6. 3-dimensional reproduction.

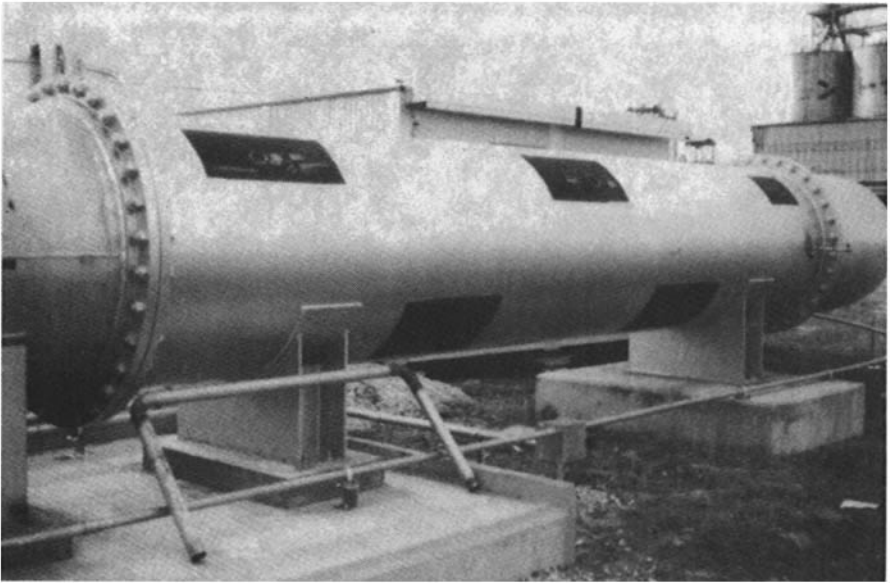


Photo 1. Overview of the test loop with patched samples.



Photo 2. Internal natural corrosion sample patched onto the test loop.



Photo 3. Internal natural corrosion sample on the girth weld in the test loop.

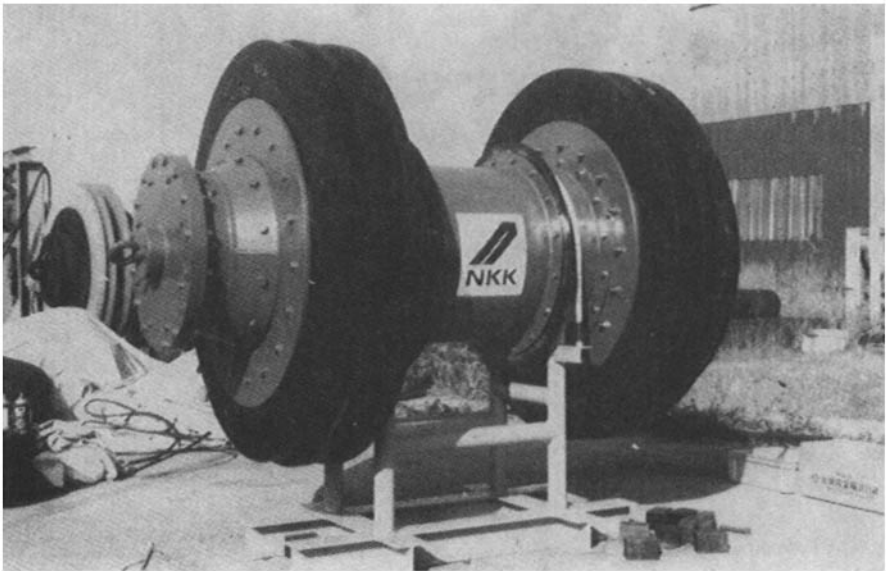


Photo 4. The bi-directional ultrasonic pig.

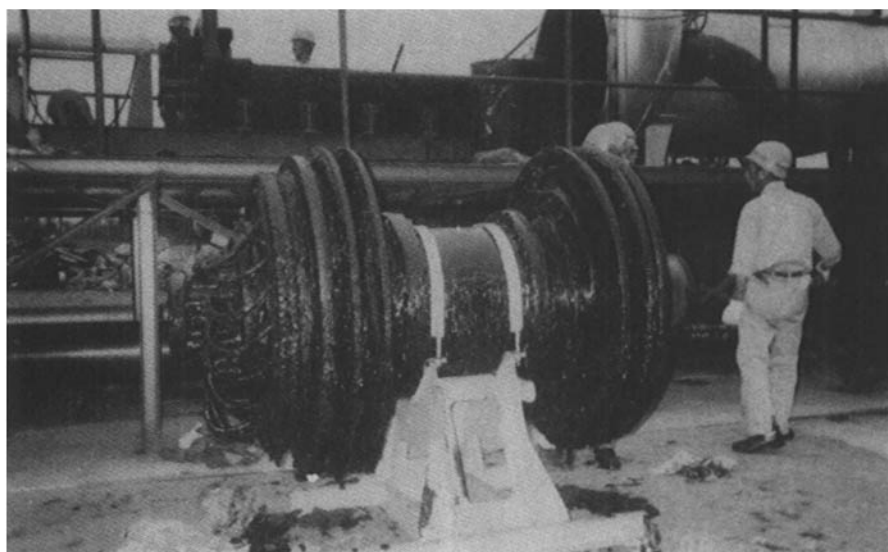


Photo 5. The bi-directional ultrasonic pig after passing through the pipeline.

CONCLUSION

The bi-directionally-travelling ultrasonic inspection pig has successfully been used to undertake an inspection of an offshore pipeline to a PLEM, and has proven its technological ability to provide valid data for efficient, cost-saving maintenance.

NKK will apply this technique to the inspection of offshore crude oil loading pipelines, where to date inspection has been considered impossible by means of conventional inspection pigs.

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CORROSION SURVEYS WITH THE ULTRASCAN PIG

CORROSION INSPECTION of long-distance pipelines is increasingly carried out by electronic surveying robots, so-called intelligent pigs. These devices locate dents, cracks, and corrosion damage by utilizing modern electronic NDT technology. A 2nd-generation corrosion-detecting pig is described in this paper, a device whose development has only been made possible due to recent advances in microprocessor technology.

BASIC PRINCIPLES

The idea of using electronic-surveying pigs for checking the condition of a pipeline is not new. During the early 1970s, a generation of research tools was developed by a number of companies which employed the magnetic stray flux method to locate corrosion in pipelines.

The disadvantages of the stray flux technology applied by these first-generation tools was their inability to measure both wall thickness and the depth of corrosion directly. These tools only reacted to a local metal loss in the pipe's wall; the error margin was quite wide. They were able to indicate the location of corrosion, but did not accurately measure its depth. Another disadvantage of this method was that other inhomogeneities in the pipe wall are indicated as defects, even though they are not always relevant to safety considerations.

For the new second-generation pig, the task was defined to measure the pipeline's residual wall thickness directly. The method of measuring wall thickness with ultrasonics was selected, because it is both a very accurate technique and has proved itself in many years of industrial use. The pig was developed by Pipetronix GmbH in co-operation with the Nuclear Research Centre in Karlsruhe.

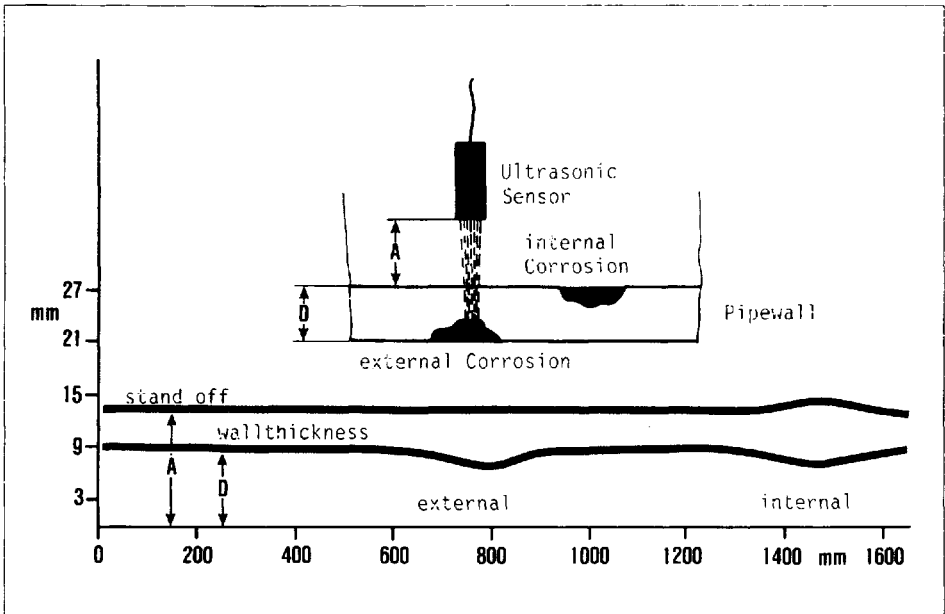


Fig.1. Basic principle of the ultrasonic technique.

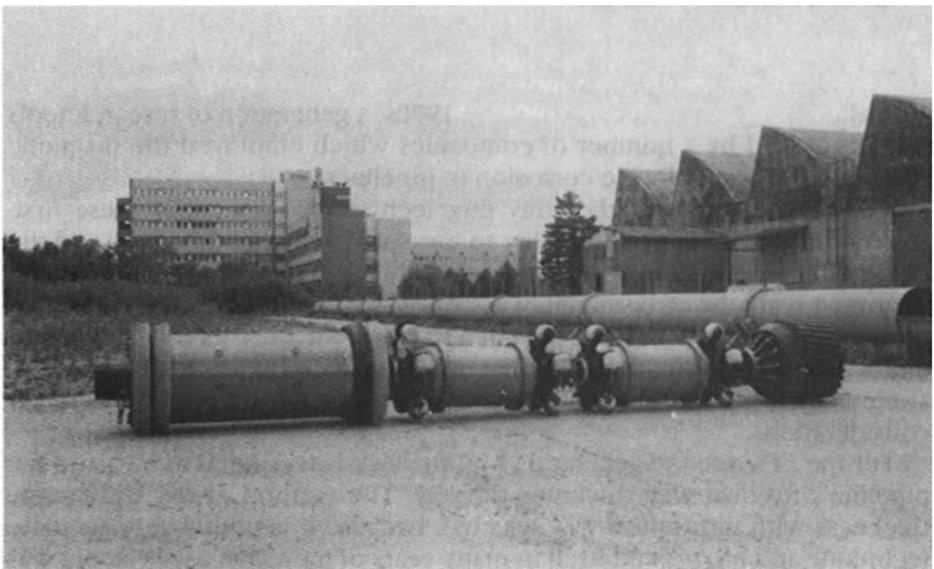


Fig.2. General view of the 24-in *UltraScan* pig.

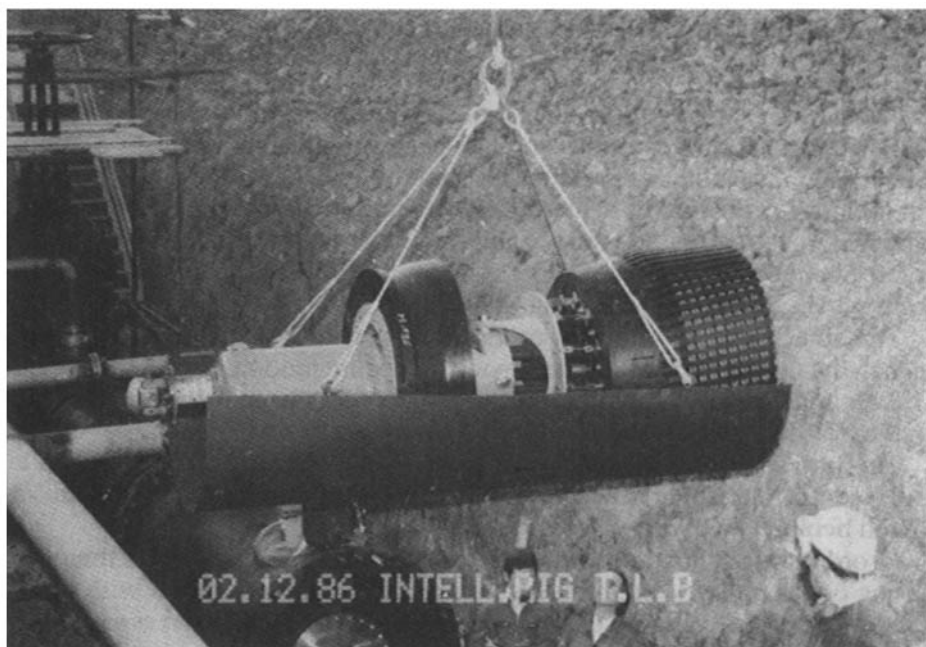


Fig.3. Ultrasonic module with a 40-in sensor carrier.

Fig.1 shows the basic principle: the ultrasonic sensor, which is perpendicular to the wall of the pipe, emits a series of short ultrasonic pulses. These pulses are reflected by both the internal and external surfaces of the pipe. The distance of the sensor from the wall, stand-off, A, and the wall thickness, D, can be determined by the time interval between the transducer exit pulse, the wall penetration echo, and the rear wall echo. The diagram shows the test readings of a sensor which has run across the two indicated defects. The line representing wall thickness clearly shows both defects; the remaining wall thickness can be read directly off the diagram. It is however, not possible to differentiate between internal and external corrosion merely on the basis of the wall-thickness data; for this reason, the distance between the sensor and wall (stand-off), A, is also indicated. The stand-off value does not change when the defect is on the exterior; when the defect is internal, it will be shown as a mirror image on the stand-off trace. Consequently, it is possible to differentiate between an internal and an external defect by combining the wall thickness and stand-off information. This differentiation is very important to the pipeline operator, since corrosion prevention measures are quite different for the two types of defects.

EQUIPMENT DESCRIPTION

The complete pig, seen in Fig.2, consists of three modules with a sensor carrier at the end of the tool. The individual pig modules are linked by flexible universal joints, and have pressure-resistant bodies that carry the electronic equipment for the survey. The first pig module rides on cups through the pipeline. These cups guide the pig and simultaneously seal inside the pipe to create the necessary differential pressure for propulsion. This module acts as the towing unit for the whole pig train.

The other units are guided by rollers or cups with by-passes. The 24-in pig seen in the illustration has a battery pack in the first module as power supply. The second module holds the data storage and the multi-microprocessor system for data processing.

The ultrasonic survey equipment is located in the third module, and a multitude of ultrasonic sensors is mounted on the sensor carrier which is towed behind.

In order to fulfil its duty, the pig must scan the entire surface of the pipe during one run. To do so, the sensor carrier (Fig.3) is equipped with eight sensor planes. The various sensors are mounted in such a fashion as to ensure complete coverage of the pipe's surface. The sensor carrier must keep the individual sensors perpendicular to the wall and ensure that the sensors are kept at constant distance from the wall. A pig with 48-in diameter (1.2m) has, for example, 448 sensors located around its circumference.

The individual ultrasonic sensors are connected via shielded cables to the ultrasonic equipment inside the third module. These cables enter the third module through a pressure-resistant bulkhead. The sensors have a special design and are pressure-resistant up to 200bars to withstand the pressure inside the pipeline.

64 sensors are combined to form a multiplex unit, each of which has a central control board and a main amplifier which supplies the 64 modular units. The individual sensors are excited by a 5-MHz ultrasonic pulse. The maximum pulse repetition frequency is 400Hz per sensor. A 48-in pig has seven multiplexed modular units for its 448 sensors. Two 8-bit words appear at the output of each modular group: one for wall thickness, and the other for stand-off. The ultrasonic module's data is passed on to the second pig module; the data flow is approx. 400 kByte/sec.

For data storage, magnetic tape recorders are still used despite the recent advances in semi-conductor storage technology, because magnetic tapes have a higher data density per volume. The *UltraScan* pig, which is subject to considerable acceleration inside the pipeline, has a magnetic tape unit that was developed for airborne applications. It stores the data on a 1-in magnetic

tape, and the unit has 10.5-in reels which can handle approx. 4 GByte of data on 28 tracks. If the untreated data on the ultrasonic module was to be recorded, the distance between two ultrasonic pulses being only 2.5mm apart, then the magnetic tape capacity of a 40-in pig would only be sufficient for 10km of pipeline

Owing to the nature of the data, it can be compressed without loss of information. The pig is equipped with an on-board multi-microprocessor system to carry out this function; the data flow is constantly monitored and compressed in such a manner that only 1/10 of the otherwise necessary storage space is actually occupied on the magnetic tape. Hence, it is possible to store 100km of pipeline on one magnetic tape without loss of any data. Since the 40-in pig has two magnetic tape recorders, it is therefore possible to store 200km on tape; this is equivalent to 80 GByte of ultrasonic data.

The magnetic tape's storage capacity is only used efficiently if the data is stored at the maximum baud rate at the selected tape speed. In order to achieve this, the data supplied by the data-compression microprocessor is stored first in the cache register. Once this is full, the data will be transmitted to the magnetic tape storage in a serial mode at a constant baud rate. A second cache register acts in the meantime as an intermediate storage for the continuous flow of data. Rechargeable silver-zinc batteries provide the necessary power in pigs with large diameters. These batteries represent the most up-to-date technology, and have twice the energy density of nickel-cadmium batteries. Pigs for smaller diameters use primary lithium cells, since rechargeable batteries do not provide sufficient energy, given the limited space available.

Data analysis

The entire software for data evaluation was written for IBM AT-compatible computers, allowing analysis of the recorded data directly at site. A very important feature is the representation of defects through quasi-three-dimensional colour charts. Fig.4 shows such a chart: the wall thickness is shown in the bottom section and the stand-off in the top section. The chart is composed of many parallel lines, each one representing the data from one sensor in colour. The y-axis represents, therefore, the unfolded wall, and the x-axis the distance travelled. A section of pipeline without defects, with the sensor at normal stand-off, is shown as white. As soon as a defect appears, a colour spot will become visible. The size of the spot indicates the area extension of the defect.

The data evaluation is carried out in steps. Since the magnetic tape unit is not efficient for handling the data because it does not have random access, all

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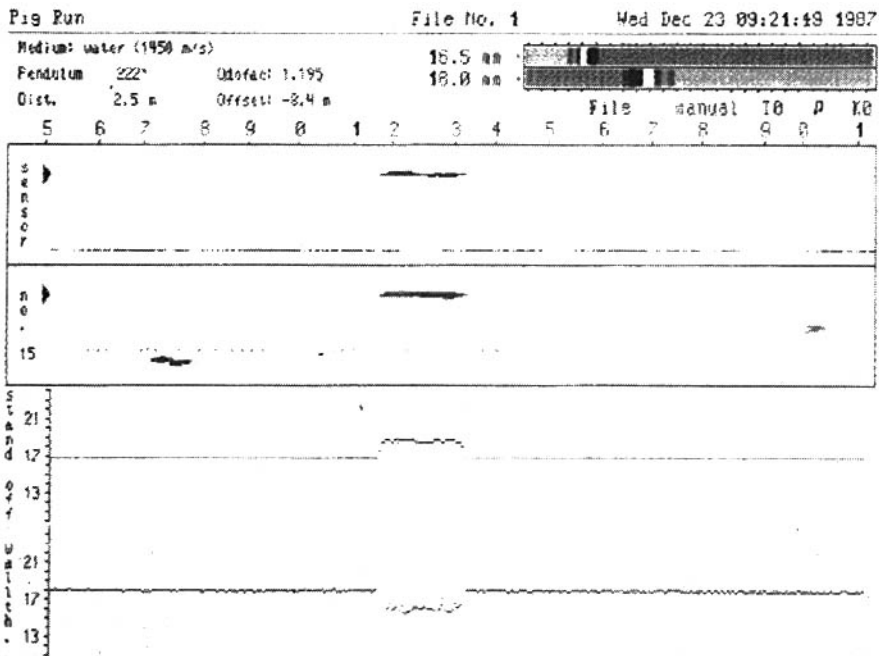


Fig.4 (Above): Colour contour chart of an internal defect (C-Scan); the upper trace represents stand-off, the lower trace represents thickness.
(Below): Single-sensor trace as a cross-section view (B-Scan).

data is transferred first onto 800-MByte optical discs. These data discs operate according to the WORM principle, and are also used for later archiving.

During the next phase, automatic analysis programs will search the acquired data under various criteria for defects. Those locations that are found to be of interest will be analyzed during the third phase by an "interpreter". They are, if necessary, documented by a hard copy which includes the C-Scan, the B-Scan and the auxiliary data.

Proven track record

The *UltraScan* pig has been used already with success in Germany, France, Italy, the Netherlands, Denmark, the North Sea and the USA. Figs 4 and 5 show typical internal and external defects as an area display (C-Scan) and as a cross-section view (B-Scan). The advantage of the ultrasonic method was clearly

Corrosion surveys with the 'UltraScan' pig

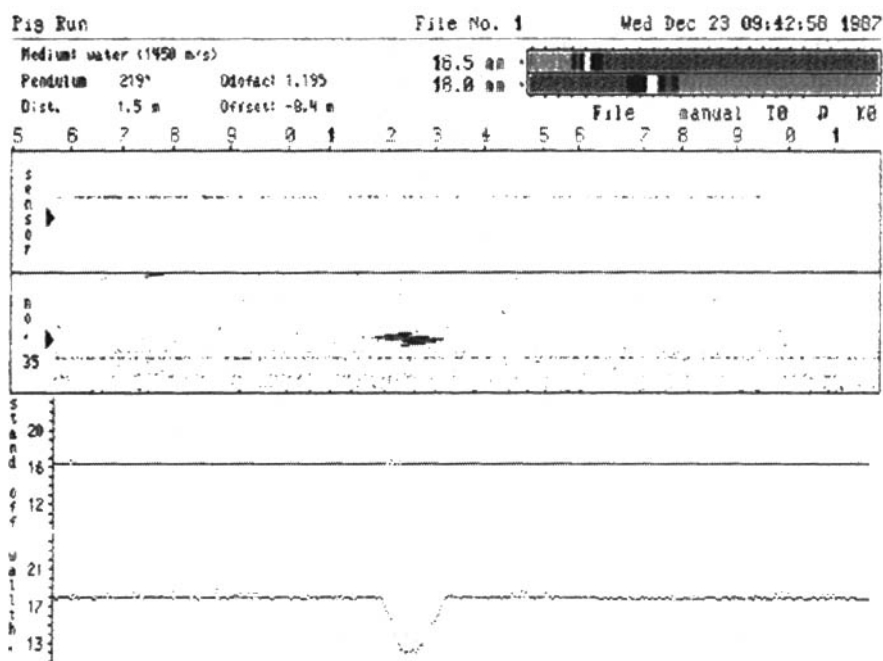


Fig.5. Trace from a typical external defect.

demonstrated during these projects. Some of the pipelines had severe corrosion, something that was already known before the survey, and continued operation was questionable. With the high accuracy of the *UltraScan* method, it was possible to isolate the really dangerous spots. After repair work had been carried out on the sections with severe corrosion, it was possible to resume safe operation of the pipeline even though minor, but harmless, spots of corrosion remained.

Up-to-date technology

The successful development of the *UltraScan* corrosion pig is closely tied to the progress made in the field of microprocessor electronics during recent years. Only with this technology was it possible to process the data flow of 400kByte/sec in the pig itself with the aid of high-performance 16-bit processors such as the 80-186 series.

The effect of the latest technology is even more pronounced in data analysis. Initially, the IBM AT's graphics' speed was slow and annoying for the evaluating technician. The desired work flow speed was only realized with the introduction of the Compaq *Deskpro* 386 series PC, which has a 20MHz clock frequency. The story is similar for the various storage mediums. The floppy discs, streamers, and Winchester discs available at the beginning of the pig's development were not suitable to store and handle the vast amount of data subsequently made available. The problem was solved only when the optical disc with a storage capacity of 800MBytes was introduced. This disc has a large storage capacity, random access, and is handy for archiving purposes.

The situation becomes even more problematic when pigs for smaller pipelines, e.g. 6-in (150-mm), are designed. Only those electronic components which are based on SMD, Hybrid, and LSI technology can be used. The magnetic tape recorders that are used in these smaller-diameter pigs are based on relic scan recorders which have appeared only recently on the market.

CONCLUDING REMARKS

The *UltraScan* corrosion pig is the first internal pipeline inspection tool that permits direct quantitative measurement of remaining wall thickness and scans the entire inner surface area of a pipeline. The development was well timed, with the 16-bit microprocessor technology and other advanced components required for the building of small-diameter tools having only just appeared on the market.

HIGH-ACCURACY CALLIPER SURVEYS WITH THE *GEOPIG* PIPELINE INERTIAL GEOMETRY TOOL

IN THE DEVELOPMENT of the inertial geometry pig, Pigco recognized the need for relating the pig position to the pipe wall. The sensors used for this during some of the initial runs provided a very good picture of the inside of the pipe wall. To meet the need for a high-accuracy calliper with the ability to accurately locate features, Pigco has improved its *Geopig*. To provide data in a useful form that facilitates interpretation, Pigco consulted with its clients and developed a software-analysis system; and a test-dig programme verified the accuracy of location and feature measurement. The paper describes the pig hardware, the analysis software, operations, and the results of the survey. Potential for structural analysis and the scheduling of maintenance is also discussed.

INTRODUCTION

Previous inertial pig development

The *Geopig* was designed to meet a large variety of user requirements using a modular system which integrates a number of different sensors. The *Geopig* can be customized and adapted to fluid or gas lines with minor modifications. The current versions can inspect pipelines of diameter NPS 10in (254mm) and above.

The strapdown inertial measurement unit (or SIMU) produces a three-dimensional measurement of inertial acceleration and angular rate directly from orthogonal triads of accelerometers and gyroscopes. Two inertial systems are currently in use: one uses an orthogonal triad of single-degree-of-

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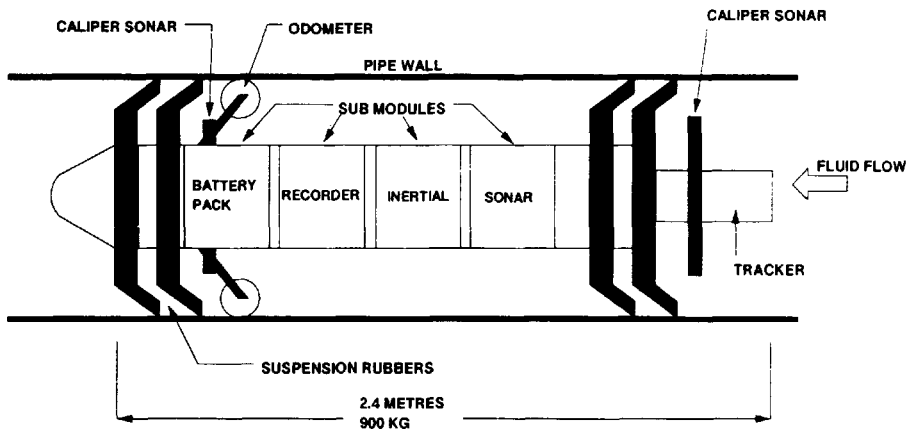


Fig.1. NPS 30 tool configuration.

freedom gyros; the other uses a pair of two-degree-of-freedom gyros. In the SIMU with two-degree-of-freedom gyros, a redundant or combined axis measurement is available. The SIMU accelerometers and gyros are complementary sensors which, when coupled, deliver the measurements for computing pipeline curvature, orientation of that curvature, and the positioning capability for location of features.

The *Geoptig* is suspended in the pipeline by rubber disks fore and aft of each carrier; this restricts the *Geoptig* to moving close and parallel to the pipe centreline. However, this guidance is not accurate enough to ensure that the trajectory of the pig coincides with the pipe centreline, and that the pig's pitch and heading coincide with the slope and azimuth of the pipeline, respectively. The actual deviations have to be determined continuously which is achieved by two rings of sonars mounted on each end of the inertial system. Combination of these sonar readings yields the pig-to-pipe translation and attitude.

The initial data set from the alignment calliper showed the ability to observe very small features in the line. It was therefore decided to expand on this capability by increasing the number of sonars. The NPS 30-in tool was designed with 72 sonars on the back ring and eight on the front for alignment. These give a full picture of the internal shape of the pipeline, with each sonar covering about 3cm of circumference.

The *Geoptig* is completed by some other sensors and devices: odometers, which measure the distance travelled, tracking transmitter for location of the

Geoptig, and a storage device and power supply which allow independent operation for long measurement periods.

Fig.1 is a schematic of the *Geoptig* for NPS 30-in sizes and larger. For a detailed description of the development of the *Geoptig*, see Adams *et al.*, 1989. For detailed description of the applications, see Price *et al.*, 1990.

Background for feature reporting

In the initial stages of development, delivery of data was in hard-copy form. A typical report would consist of several three-ring binders; for several reasons, this was unsatisfactory. It was difficult and time-consuming to go through the data, and analysis by manual techniques did not always result in correct answers. With the large volume of data, many important features could be missed. Storage of the information was expensive.

To solve many of these problems and provide a system that would allow easy and precise analysis, Pigco developed a PC-based software package. By using the new optical disk technology, the processed data from a 300-km line section would fit on one cartridge. Although streaming tape could be used, it would not allow random access of the data points. Access times for the optical drive are only slightly slower than for the normal hard disks found on many PCs.

By automating many of the search functions, the software allows rapid screening or, if desired, a feature-by-feature step-through the line. Calculation of effective dent height was made uniformly and consistently, and not subject to interpretation error.

All the data is contained on the optical disk record; any point can be called up and viewed. By interfacing with any of a number of hard-copy devices, prints in colour or black can be produced as desired.

HARDWARE

Calliper sonar

The sonar devices are mounted in a ring and spaced at precisely-machined constant angles around the ring on the pig. An accurate offset is added to these ranges to give the actual distance from the centre of the carrier to the pipe wall. These observations are in a polar coordinate system and are converted to a rectangular coordinate system to form the pseudo-observations.

Pipeline Pigging Technology

Two rings of sonar sensors in liquid, or ultrasonic sensors in gas, scan the wall of the pipe and determine the pig-to-pipe translation and attitude. The use of sonar or ultrasonic technology increases the reliability and accuracy without the dependency on mechanical detectors and without contact on the wall.

Configuration of the sensors

The sonar or ultrasonic devices that range to the pipe wall are designed to stand-off 10 to 15cm (4 to 6in). Shorter distances cause an inability to read the transit time with sufficient accuracy for precise distance measurements. If the distances are much longer, it is difficult to obtain sufficient signal strength to correctly pick the return time.

In the NPS 30-in tool, the sensors were spaced to cover 3cm (1.25in) of the pipe wall circumference. At a run speed of 1m/s (3.3fps) and a recorded sample rate of 32Hz, the length of the sample window is 3cm (1.25in). The footprint of a sonar on the wall has a diameter of about 1cm (0.4in).

Timing

To minimize interference from one sensor with the others and the effect of reflecting signals, the sensors are pulsed opposite the last one plus one.

Originally, the *Geopig* sonar sensors were sampled at 32Hz using a medium-strength power level. The return signal was recorded regardless of the amplitude. In the early runs, single sensor spikes occurred on one or two scan lines. These were most probably reflections off particles in the oil or refraction off the side of a small dent.

On subsequent runs the sampling rate was increased to 64Hz. The first pulse was low power; if the return signal amplitude was too low, a more powerful second pulse was sent out. If the amplitude of the second return signal was stronger, it was recorded as the pipe wall return.

This sequence of power pulsing significantly reduced the false returns on the later runs.

Strapdown inertial navigation system

The selection of a particular SIMU was based primarily on size, accuracy, power requirements, and cost. The size requirement was dictated by the smallest pipeline diameter and the ability to negotiate bends in the line. The accuracy requirement was to provide radius of curvature measurement to

better than 100m. There are basically two ways to determine the curvature of a pipeline by a SIMU: via cross-track acceleration (centrifugal force), or via cross-track angular velocity.

Low-accuracy SIMUs are not accurate enough to use their acceleration to determine the curvature. However, the acceleration is necessary to orientate the curve with respect to the vertical (see Knickmeyer *et al.*, 1988). Power requirement was an important consideration due to the duration of pipeline runs of a week or more.

Weld detection

Circumferential weld-detection sensors are mounted in one of the pig rubbers, and sense the change in material at the weld. The output of each of the three or four sensors is an electrical pulse. At any time, one of the sensors may pick up the long seam weld or other changes in the metal, but only at the girth weld will they all fire simultaneously. The resulting girth-weld indication is used to correlate the pig data to as-built plans. The welds also build a log of pipe joints for future comparisons. In epoch-to-epoch measurements, the historical information on weld separation provides an indication of the axial forces acting on the pipeline.

Odometers

Velocity information computed from odometer wheels bounds the errors which occur in the time integration of the inertial data. At the same time, these sensors provide a system chainage for the pig through its travel down the pipeline. The hinged wheels maintain contact with the pipe wall by spring tension; the pivot allows the wheels an additional degree of freedom to maintain a tangential orientation when the pig is negotiating bends.

Data processing

Calliper processing

The sonar ring measures distances from the pig carrier to the pipe wall, thus capturing a cross-section of the pipe. These ranges are processed using adjustment techniques to compute the centre of the pipe with respect to the pig, and the pig-to-pipe attitude, using circular and ellipsoidal models.

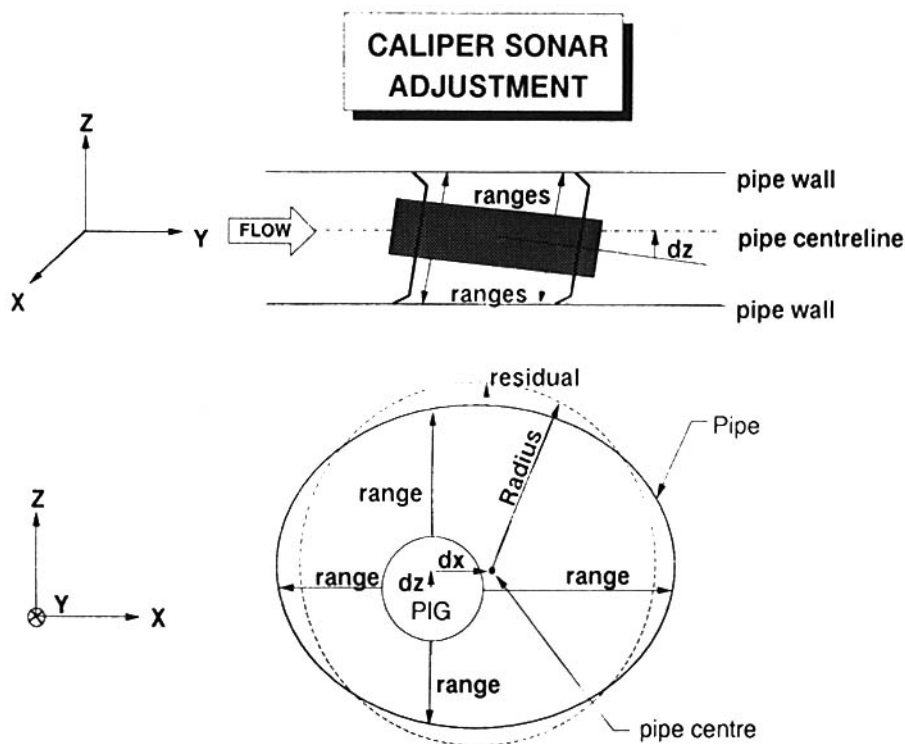


Fig.2. Calliper sonar adjustment.

Deviations from the model (adjustment residuals) give the cross-sectional picture of the pipe with determination of dents and ovality, as shown in Fig.2.

The on-board processing consists mainly of packing the data to take as little tape space as possible. On recovery, the processing consists of:

- spinning the data to the correct clock position, based on the accelerometer output from the inertial system;
- correcting for offset of the sensor from the centre of the pipe;
- correcting for changes of the velocity of sound in various media.

Strapdown inertial unit processing

A SIMU is ideally suited to the task of providing trajectory information in the local sense for several reasons. Firstly, it experiences rotations due to curvature of the pipeline directly, because its movement is constrained by rubber disks. Secondly, output is at a high rate, typically 16 to 64Hz, hence profiles can be analyzed at a very high resolution based on pipeline fluid or gas-flow rates. For a structural analysis of critical pipeline curvatures, accurate local measurement is required. This local accuracy characterizes inertial instruments, so that a low-accuracy SIMU (gyro drift $10^\circ/\text{hr}$) is sufficient for the problem at hand (see Schwarz *et al.*, 1989).

SIMU processing consists of calibration, alignment, mechanization, and Kalman filtering modules. Various updates stabilize the computation of position and attitude. The error state is comprised of misorientation, position, velocity, accelerometer bias, and gyro-drift parameters.

The processing provides:

- position (latitude, longitude, height, or UTM or local coordinates on any datum) of the trajectory;
- attitude of the pig (pitch, roll, yaw), and consequently of calliper and other sensors;
- statistical information to qualify the computed quantities.

The SIMU processing is, apart from the sensor error compensation, independent of the actual unit used.

Velocity processing

Velocity information computed from Doppler sonar and odometer wheels bounds the errors which occur in the time integration of the inertial data. At the same time, these sensors provide a system chainage and continuous checking between the two sensors to eliminate odometer slippage and provide scale-change estimation. The velocity-processing module combines the velocity data from the odometer wheels and the Doppler sonar, and yields the best velocity possible for use in Kalman filter processing.

Continuous checking between the two odometer wheels (or four, depending on configuration) determines odometer-wheel slippage and is corrected. The redundancy also allows for relative scale estimation between the wheels. The velocity processing for the odometer wheels makes use of the redun-

dancy to compute the best velocity possible for use as input observations for the Kalman filter. The along-track velocity is computed by using the recorded times of the reflectors passing by the proximity sensor. The measured circumference of the wheel over time interval yields the velocity for each wheel. Opposing wheels are averaged to compute the centre line chainage and velocity of the pig.

DATA PRESENTATION: THE *GEODENT* SOFTWARE

Description

The *Geodent* program is designed to assist in analyzing the status of the inside of an oil or gas pipeline using the data collected from the Pigco Pipeline Services Ltd *Geoptg*. The data is collected and processed at intervals along and around the pipeline for its entire length; included are the coordinates in Northing and Easting, chainage, the elevation, the inside diameter, the ovality, and the weld to weld distances. By examining this data in detail using the powerful graphics in *Geodent*, anomalies can be identified and analyzed to quantify the size, shape and location of dents, buckles, and so on.

The major features of the *Geodent* program that enhance its use are:

- analysis is conducted on a standard PC-compatible computer using menu-driven displays that minimize the learning curve to efficiently and effectively analyze the pipeline condition;
- all features and anomalies are located with accurate coordinates and chainages for field location and correlation to the as-built drawings;
- the *Scan* feature grades all features for the entire length of the pipeline, prioritizing the analysis and allowing quick access to problem areas;
- multiple windows facilitate viewing of a potential anomaly in many different perspectives, scales and colours, including three-dimensional, contour or section;
- interactive measurements yield rapid determination of the size, shape and extent of any anomaly;
- computer-generated reports provide automatic grading of dents, listing of pertinent details, and incorporating engineering comments;
- the program can be interfaced with over 200 printers and plotters for presentation and analysis.

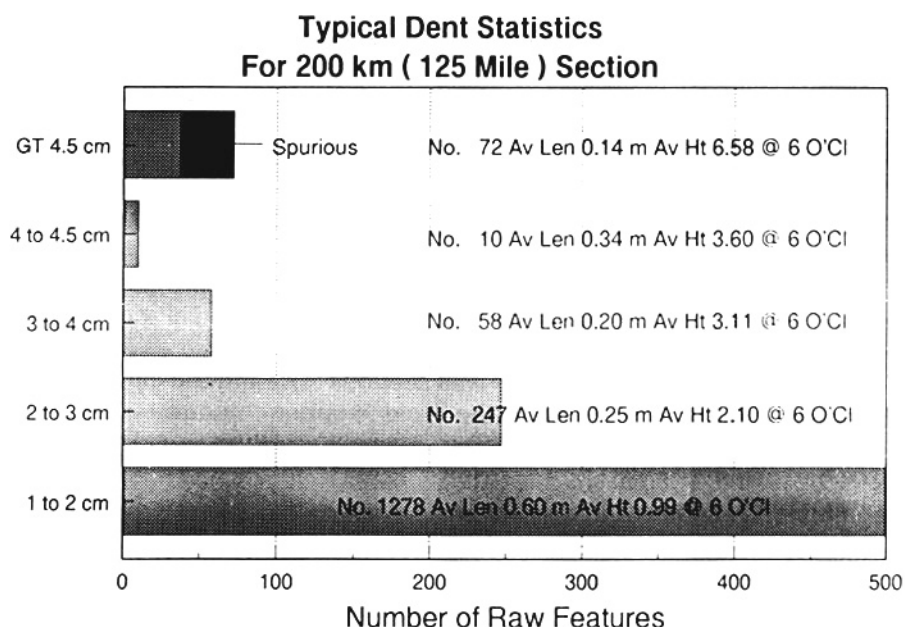


Fig.3. Typical dent statistics.

The utility programs *WELDREPT* and *DENTREPT* provide reports of all the welds and summaries of dents meeting user-defined specifications.

Reporting functions

Dent report

DENTREPT produces a summary of the features (Fig.3) identified during the run of the *Geoptg*. The search variables are the height of the feature and the number of scan lines. The number of along-track scans that a feature covers is related to its length, and depends on the pig speed and the sampling rate, which are variables used to determine the data points included in the search.

The program provides an output that is summarized in Table 1 below. Each feature is identified with a number that is used in more detailed analysis.

Table 1. Typical output parameters.

Feature number	Time (sec)	Chainage (m)	Length (m)	Maximum ovality	Average ovality	Clock position
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Weld report

The *Geoptig* system measures with the weld detect sensors each girth weld. These welds are used in the database as primary identifiers and in the kinematic analysis as boundary points. The *WELDREPT* program gives a listing of all the welds, the run time when they were detected in seconds, and the chainage in meters.

The valves (V), the start of heavy-wall sections (SH) and the end of heavy-wall sections (EH) are identified in the Weld Number column:

Weld number	Time (sec)	Chainage (m)	Chainage (ft)	Length (m)	Length (ft)
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Overview functions

Dent

The drag menu *Dent* on the main menu allows the number and extent of the dents on the database to be summarized graphically. The chainage or time, the computed out-of-roundness (including dent height less average ovality), and the lengths of the dents, are summarized graphically. The welds, thick-wall sections, and valves are identified on the display. The detail display can be used to zoom-in on an area in the main display. The facility to locate a dent and then exit to the analysis program allows rapid evaluation of the feature.

The width in time or metres of the display may be selected for either the *Dent* or *Curve* mode. The minimum ovality or dent depth and minimum length in scan lines may be selected as a criterion for those features that are included in the summary.

Curve

As part of the *Dent* mode there is also the ability to plot the curvature of the pipeline. The ratio of the detected bend in the pipeline to the pipeline radius is indicated as potential strain according to the formula:

$$\kappa = (r_p - r_s) \times 100$$

where κ = curvature,

r_p = pipe radius, and

r_s = measured radius of centre line.

Display functions

The screen

The display screen for *Geodent* has the following basic framework:

- a main menu bar across the top of the screen, with pull-down menus selectable by the mouse, arrow keys or keyboard letters;
- a main display on the screen, where the pipeline data is displayed in a selectable format;
- a detail display on the screen, where a zoom of the main section is displayed in a selectable format;
- information panels on the left of both the main and detail displays, where either the colour spectrum or information about the dent or feature is displayed;
- data panel at the bottom of the screen, where six lines of information are displayed concerning the program status or data requested.

Types of display

This section describes the graphic display types that are available on menus on the main display bar under *Display*. Each display will show the options available for that menu.

Thermal: depicts a section of the pipeline in a selectable colour scheme. Each calliper sonar reading in the window area is colour plotted as a function of its residual value from a circle on each scan line and for the display width.

Cross section: plots all sonar ring readings within a section of the pipeline at a distance or time along the pipeline (scan line). Each sonar reading is plotted relative to a theoretical vertical line that would represent a circle. The plotted deviations from this line represent the magnitude of the dent, ovality or other feature.

Profile section: plots the readings from each of the calliper sonars within a section of pipeline as it transits the pipeline. Each sonar reading is plotted

relative to a theoretical horizontal line that would represent a point on a circle. The plotted deviations from this line represent the magnitude of the dent, ovality or other feature.

Round section: plots each set of sonar readings within a section of the pipeline at a distance or time along the pipeline. The view is as if looking in the end of the pipeline at the end of the section. Each sonar reading is plotted as a residual from a circle.

Contour section: is similar to the *Thermal* section, except that the sonar readings are contoured and a line of constant depth is determined and colour plotted.

Gyro and diameter: plots the readings from the cross-track gyroscopes of the inertial system. This is useful in confirming welds, as the gyroscopes will see deflections as the front and rear cups of the pig cross the weld or any dent. If, for example, there is some foreign matter clouding a particular sonar or group of sonars instead of an actual dent, then there will be no perturbation of the gyros. This helps to distinguish real features from measuring errors or transducer problems. Also plotted is the best-fit of all the calliper sonars to give a reading of the inside diameter of the pipeline.

3D plot: provides the ability to show the feature in a three-dimensional view. The viewing perspectives in the horizontal and vertical can be changed to give different perspectives. The vertical exaggeration is five times on the vertical (depth) that on the horizontal to make the features more distinguishable.

Ptg movement: a more quantitative correlation of the dents from the gyro is possible using this display, which shows the horizontal and vertical movement of the *Geoptg* as it transits the pipeline. The movements are in centimetres, and are related to the size and location of the feature.

Hardware requirements

Geodent requires a PC-compatible computer with the following minimum requirements:

- 640K of memory
- DOS 3.0 operating system
- 40Mb hard disk
- 1.2Mb floppy disc drive
- math coprocessor
- VGA or EGA colour graphics screen
- 2- or 3-button *Microsoft*-compatible mouse driver

High-accuracy calliper surveys

For production pipeline analysis, the following PC-compatible computer is recommended:

- 1Mb of memory
- extended memory manager
- DOS 3.0 operating system
- 300Mb hard disk
- 1.2Mb floppy disk drive
- math coprocessor
- VGA (640 x 480) 16-colour graphics screen
- 2- or 3-button *Microsoft*-compatible mouse driver
- SUMO* read/write optical disk drive
- HP Paint Jet* colour plotter

ANALYSIS OF FEATURES

Preliminary evaluation

The first step in determining the extent of the out-of-roundness problem is to set criteria and determine the number of anomalies that exceed these levels. *Geodent* provides two ways to do this. The dent-reporting utility can be used to provide a hard-copy listing with dent numbers assigned to each feature. The dent number can then be referred to in future analysis and verification digs. The dent display portion of the main program with a suitable window width can also be used to identify features that require further analysis (Figs4-7).

Detailed analysis

Occasional sonar drop-outs, refraction from dent flanks, and reflections from particles can cause a feature to appear or be much larger than it really is. The redundancy of the *Geopig* system provides several ways to verify that there is a significant feature present and its size.

The gyroscopes in the strapdown inertial unit are affected even by the slight movement the pig experiences in crossing a girth weld. The gyros will be deflected by any dents. From the geometry of the tool (Fig.1), it can be seen

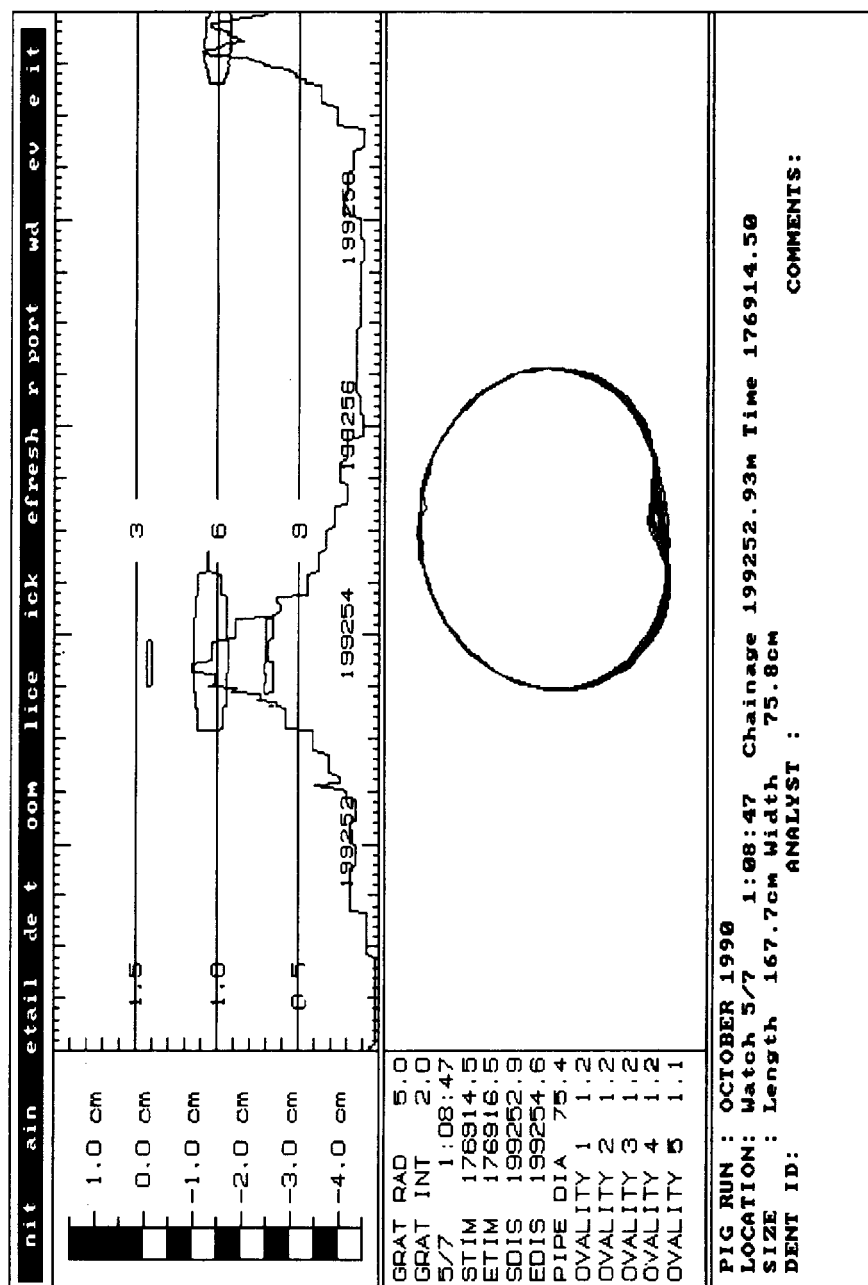


Fig.4.

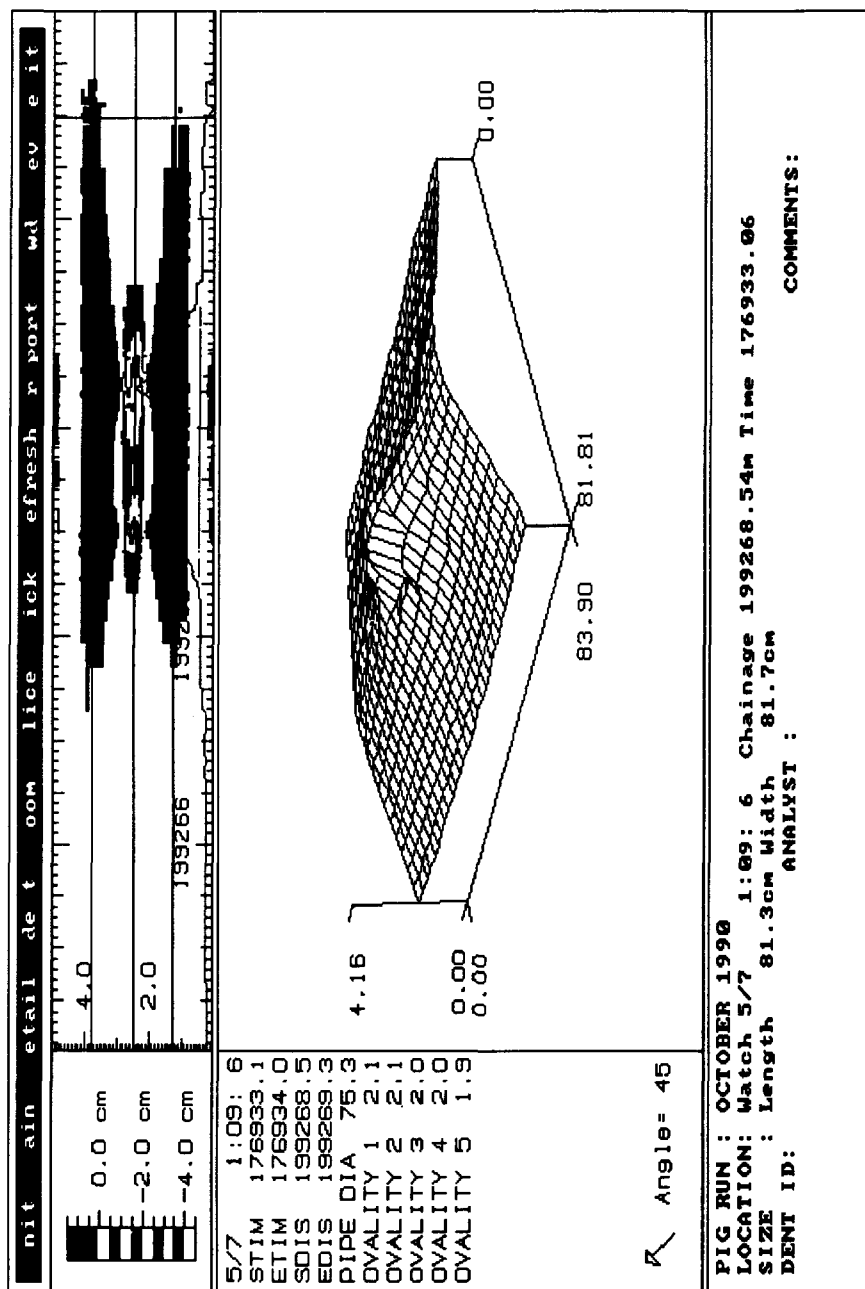


Fig.5.

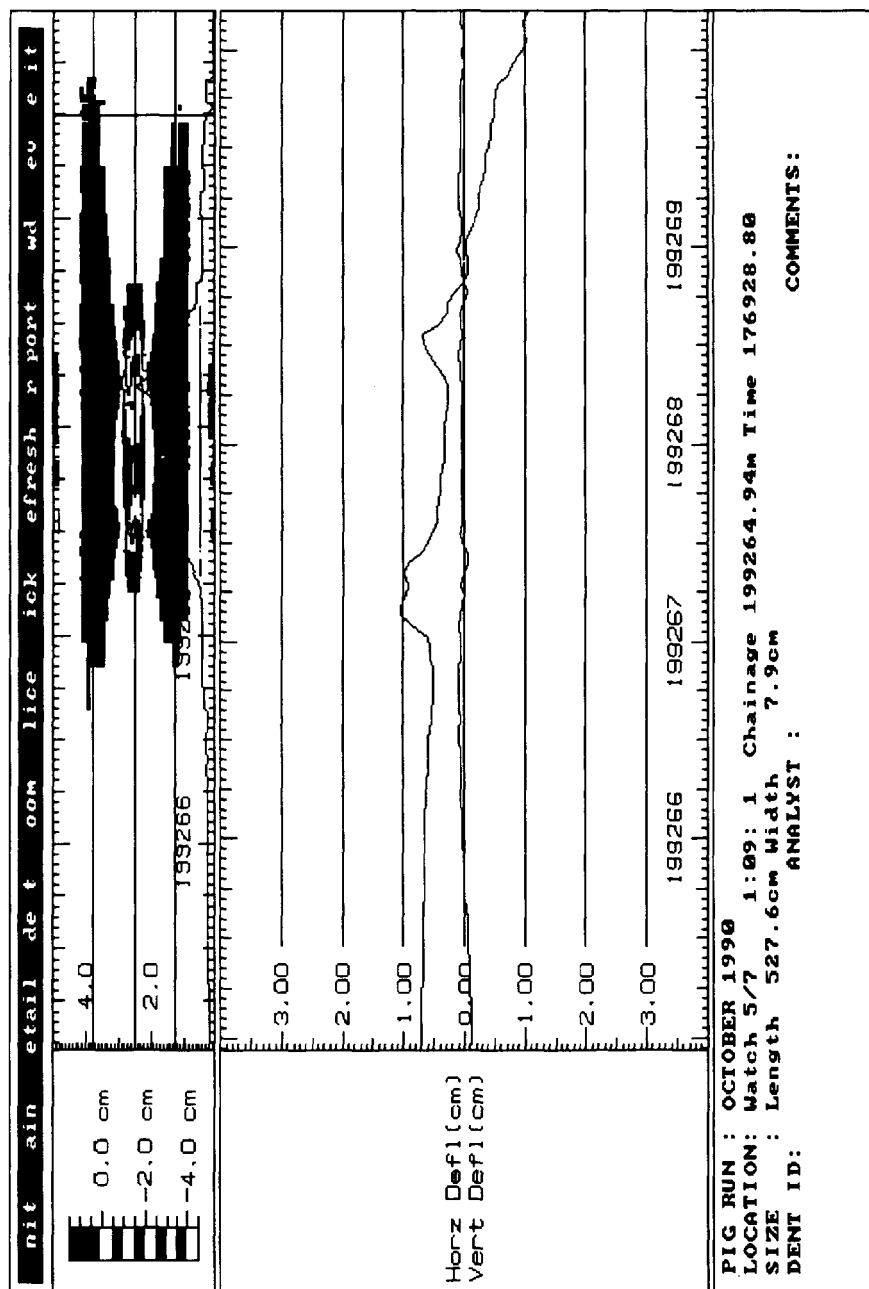


Fig.6.

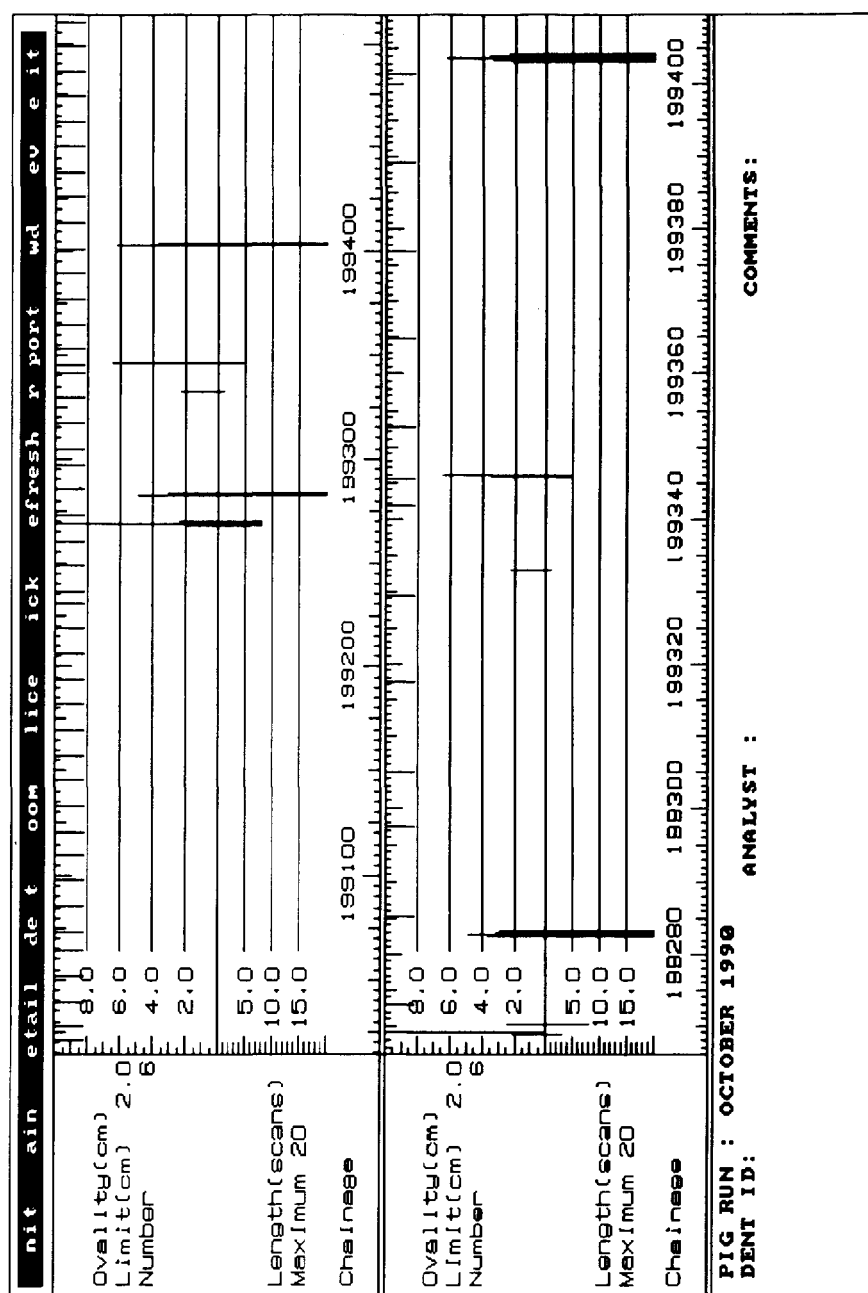


Fig.7.

that the front cups will cross the feature 1.89m before the sonars detect it, and the rear cups will be deflected 0.42m before the feature. By using the *gyro and diameter* detail display, and selecting a zoom window at least 2m before the dent, the gyro movement will verify that there is a true feature.

To check the size of the feature, the *pig movement* display is used. From geometrical considerations, the size of the dent will be three times the total movement of the front cup. This movement will be, for the NPS 30 pig, 1.89m before the callipers measure the dent. The total movement can be calculated by taking the square root of the sum of the squares of horizontal and vertical movement. Dents that are short in the long-track direction (less than 0.15m in length) will show movement as the dent falls between the pig cups. As the rear cups pass over the dent, the pig will move in the opposite direction to its initial deflection. The size of the reverse move is somewhat smaller than the first movement.

The *round* or *slice* displays are useful in visualizing the calculation that is used in determining the effective dent height. Pigco adapted the techniques used to measure dents in the field to the measurements from the *Geopig* calliper sonar. The technique used in the field was to measure the minimum diameter with a pipeline calliper at the deepest part of the dent. The ovality was measured by taking the calliper reading at right angles to the minimum diameter and deducting the nominal diameter. The effective dent height was then determined by taking the minimum diameter from the nominal diameter, less half the ovality.

This calculation is done automatically in the *Geodent* program, and shows on the left box of the display as *Ovality*, 1 through 5. The values shown as *Ovality* are the effective dent height for the five largest dent readings within the zoom box. The calculation is as follows:

- maximum deviation inward from the nominal pipe radius and the sensor number are determined for any particular scan line;
- the deviation at 180° to the maximum deviation or, in the case of the NPS 30 tool with 72 sonars, at the sensor number plus 35, is added;
- the deviations at 90° and 270° or sensor number plus 17 and 53 are averaged and subtracted;
- the resulting *effective dent height* (called *ovality* in the display) is shown and plotted.

Feature summary

Because of the accuracy of the calliper sonar, a large number of potential features show up. Most of the objects that show up in the smaller sizes are normal, such as the slight out-of-roundness in bends, ovality in deep overburden, and changes in wall thickness. In the largest sizes, all the sensor drop-outs and bad readings show up. Although the number of these is significant compared to the dents, when considering the fact that the 72 sensors are firing 64 times a second for several days, it can be seen that there are not many spurious readings.

Statistics

A typical section 200km (125 miles) in length contains over 1500 places where the total out-of-roundness or deviation from the ideal circular shape exceeds 1cm (3/8in). As one would expect, the overall average clock position of these is at 6 o'clock, or on the bottom. The average length is 0.5m and the average height is 1.5cm. The distribution shows over three quarters lie between 1 and 2cm (less than 3% of nominal diameter).

Data spikes

The single data spikes that were observed in the early runs were, to a large extent, removed by changing the timing and power levels. Later runs have shown very few spikes, less than 40 in 72 hours run time.

Dent verification

Five sites were dug up to verify the location and accuracy of the *Geoptig* measurements. Although there was a month time lag between the measurements and the overburden had been replaced when the internal measurements were taken, all five dents compared within 1.5mm (or 60 thousandths of an inch). The ovality had increased in two of the cases from the dig to the internal measurement as might be expected. Table 2 compares the results of the test dig program with the *Geoptig* measurements.

Table 2. Test dig comparison 76.2cm NPS 30 pipe.

Clock position	Minimum diameter (cm)		Effective dent (cm)	
	Test dig	<i>Geoptg</i>	Test dig	<i>Geoptg</i>
7	74.0	74.15	2.2	1.9
7	75.1	74.95	1.1	1.0
6	74.6	74.50	1.3	1.4
6	73.5	73.35	2.1	2.2
6	74.6	74.70	1.6	1.3

As the dents were small (less than 3%) measurement errors, changes in temperature and pressure could have accounted for the differences.

CONCLUSIONS

Kinematic analysis using the structural analysis system

The kinematic analysis capability of the structural analysis system estimates the main internal structural deformations using the displacement predictions and the measured geometry alone. These structural deformations include all the axial, bending, and circumferential strain components necessary for limit-state analysis. Static stability analysis can also be done in any window length of interest.

The structural reliability analysis system therefore has been developed with a powerful database management system, and three-dimensional graphic capabilities, to allow efficient access and viewing of all measured data, processed data, and analysis results in any alignment window of interest. Report files can then be interfaced with a CAD system to client specifications.

When used for pig data analysis work, the measured point-to-point curvatures computed from the azimuth, pitch and roll of the inertial system are used to delineate the initially-constructed straight pipe and construction bend pattern. Finite-element boundaries are assigned at least to all weld and

construction bend tangent points. Piecewise continuous isoparametric finite element shape functions are then automatically fitted to measured centreline coordinates bounded in each element length, using least squares adjustment procedures.

Similarly, cylindrical shape functions are fitted to the sonar data in each pipe joint, thus giving diameter and wall-thickness data that can be statistically compared with the pipe specifications, and with random deviations from internal diameter expectations due to dents, wrinkles or internal corrosion effects. The finite element centrelines are then consistently mapped to a reference plane initial geometry, representing a datum strain and stress-free geometry of straight pipe and construction bends for structural simulation and reliability analysis work. The cylindrical fitted data are amended at this stage for internal pressure and thermal effects.

The centreline tangent vector misalignment at welds is computed and used to correct the displacement vector used in the kinematic and structural simulation work, so that normal construction "doglegs" at girth welds are not included in the structural demand computations of structural deformations and curvatures.

All data-acquisition statistics are propagated through to the functional structural model for damage search, kinematic analysis, simulation, multi-run rectification and correction for temperature and pressure differences, and static reliability-analysis work including stability. The kinematic analysis is the minimum required analysis effort necessary for an objective location of any existing damage. Additional analysis is done in accordance with client requirements.

Applications

The uses of the *Geoptg* for pipeline geometry surveying have been expanded beyond the original curvature monitoring, strain measurement and precise location, to include high-accuracy calliper. The ability to interactively analyze all features and make determinations of the structural significance of those features has enhanced the ability of operators to maintain operating conditions of pipelines. In addition, the *Geoptg* can be used to evaluate corrosion problems and, based on considerations of the total pipeline condition, determine which dents, wrinkles, or wall thinning need to be replaced to maintain system integrity.

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RECENT ADVANCES IN PIGGABLE WYE DESIGN AND APPLICATIONS

INTRODUCTION

There are four subsea piggable wye junctions in the North Sea at present (Fig. 1) and four more are on the way. The offshore oil and gas industry is quite rightly cautious about having them, with concerns centring on whether they can be reliably pigged. On the other hand, as operators concentrate on developing the existing pipeline infrastructure, wyes show many advantages, particularly in reducing the number of import risers on platforms from other fields. These two main issues: the design of piggable wyes and their applications, are addressed in this paper. Ways of improving on present designs are identified, and the potential for use of wyes in field development is discussed.

Regarding design, this paper reviews the designs that have been used to date, the pigging tests which were carried out on them, and operators' experiences of pigging them in practice. Based on recent work on the design of wyes for two high-pressure gas pipelines, this paper goes on to suggest ways of improving present designs to make them lighter and more easily manufactured.

Typical field developments making use of wyes, tees and risers are compared and contrasted to show where wyes are best employed. Putting in a piggable wye is by no means a universal panacea, but there are instances where it can eliminate additional risers by combining flows into a single riser, or could change the field development concept from a collector platform to a subsea junction at a safe distance from the platform.

NORTH SEA WYE JUNCTIONS

Table 1 shows the wyes presently planned and installed in the North Sea. The first wye was installed by Occidental in 1978 on the 18-in gas pipeline between *Piper Alpha* and *MCP-01*. Illustrated in Fig. 2, it was made from a

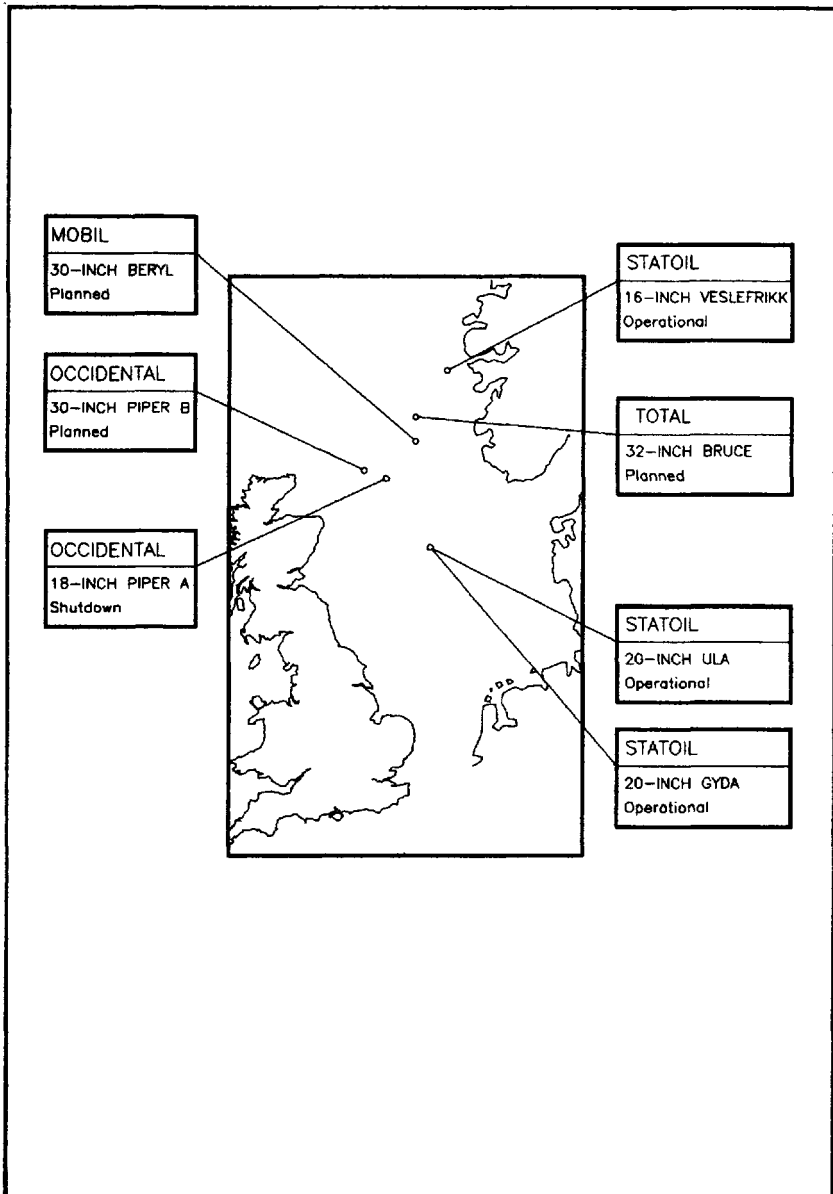


Fig.1. North Sea wye locations.

Recent advances in piggable Y design

Pipelines	Operator	Product	Size (inches)	Status	Pressure (psig)
Piper to MCP-01	Occidental	Gas	18	Shutdown	2612
Ula and Gyda to Ekofisk	Statoil	Oil	20	Operational	2026
Gyda to Ula wye	Statoil	Oil	20	Operational	2026
Veslefrikk and Oseberg C to Oseberg A	Statoil	Oil	16	Operational	1682
Beryl and Brae to St Fergus	Mobil	Gas	30	Planned	2500
Piper and Claymore to Flotta	Occidental	Oil	30	Planned	2160
Bruce and Frigg to MCP01	Total	Gas	32	Planned	2160

Table 1. North Sea wye junctions.

single forged block with machined straight bores of the same diameter as the pipeline at a 30° included angle. It was pigged during commissioning but rarely during operation due to the high quality of the gas. The spare branch was never connected up, and the pipeline and wye are now shut down. However, Occidental is to install a further wye of a similar design as part of the *Piper* redevelopment. This will be a 30-in block with straight bores at a 22° angle. It will replace the *Claymore* tee junction.

In 1986 Statoil installed a wye in the 20-in oil line from *Ula* to *Ekofisk*, 4km from *Ula*. Illustrated in Fig.3, the bores are curved and enlarged with a 30° included angle. The enlargement of the bores reduces the drag on the pigs as

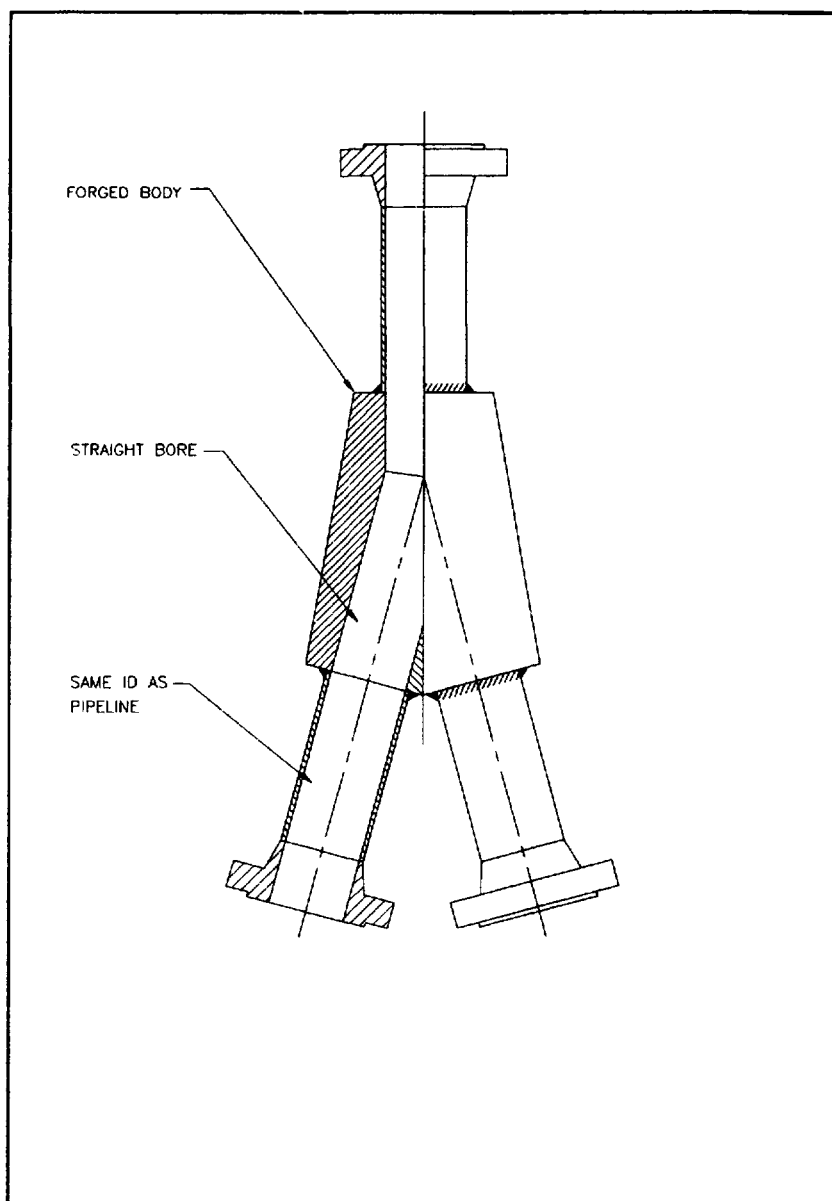


Fig.2. Wye piece machined from a forged block.

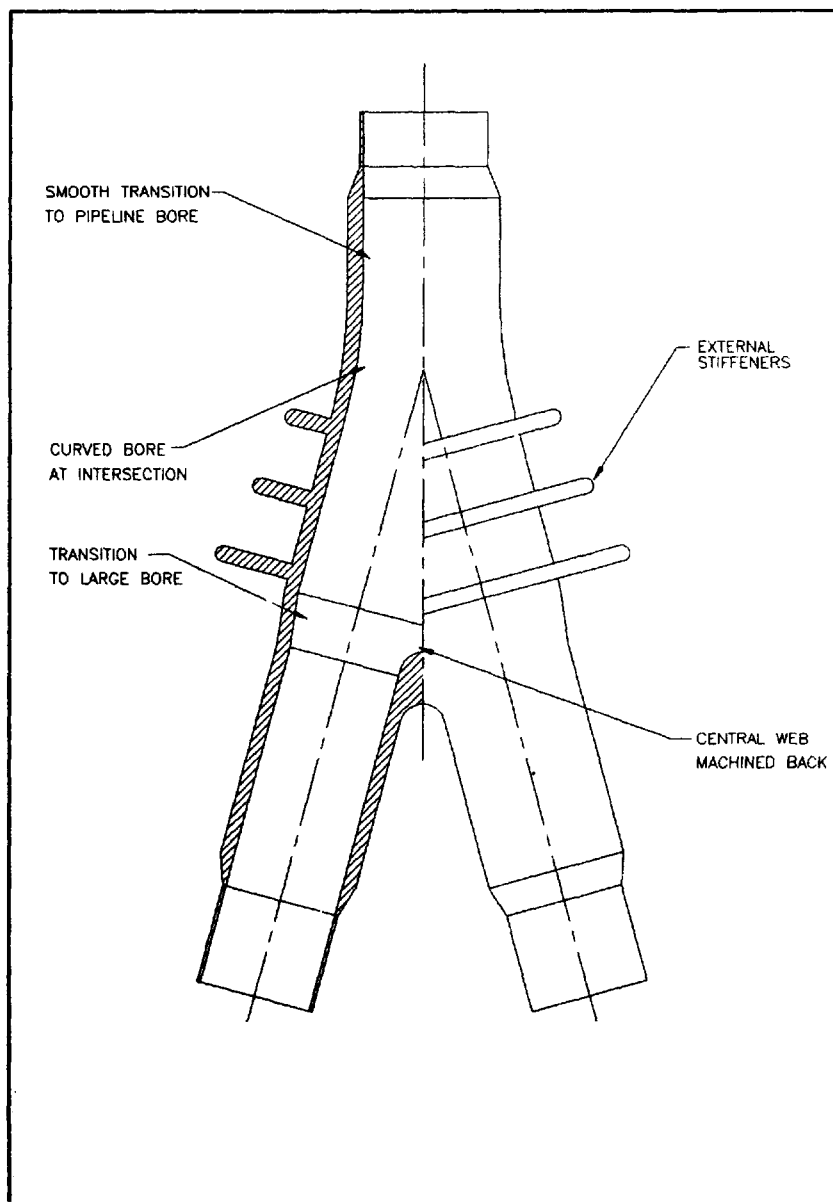


Fig.3. Cast or forged wye.

they pass through the junction. The wye piece has external stiffeners, and the web between the incoming bores is cut back and rounded off. This design has been successfully manufactured by two routes: both by casting and machining the bores, and also by forging components, welding them together and then machining.

The *Ula* pipeline has been pigged regularly, at intervals of about every two weeks, for wax removal. Cupped pigs with elongated bodies are used such that there is always at least one set of cups sealing to provide the drive as the pig negotiates the enlarged bore at the wye.

Statoil has now connected the *Gyda* pipeline to the spare branch of the *Ula* wye, and has installed a second wye of the same design in the *Gyda* line still leaving a connection available for further entrants. This combination of two wyes in series has been successfully pigged on a regular basis for wax removal since *Gyda* started exporting oil in June, 1990.

Statoil has installed a third wye junction, connecting the 16-in *Veslefrikk* and *Oseberg C* pipelines to *Oseberg A*. This reinforces the marked trend for those, such as Occidental and Statoil, who already have wye junctions, to install more. Two further operators are to install wyes, both of them large-diameter. One is to be inserted in the 32-in *Frigg* to *MCP-01* gas pipeline for the Total *Bruce* project, and the other in the 30-in *Beryl* pipeline by Mobil. As shown in Table 1, these latter are significantly larger than the 16 to 20-in wyes presently in service.

RESEARCH AND DEVELOPMENT

A comprehensive testing programme was carried out to develop the Statoil wye design and prove its piggability. The tests were carried out by A.R.Reinertsen AS for the Statoil *Ula* project in 1983-85. They were based initially on a 6-in acrylic plastic water-driven loop, where a variety of types of pig were observed passing through a convergent wye[1]. In the course of 450 runs, a preferred concept for the wye was selected and the branch angle optimized. A further 100 runs were then carried out on a full-scale 20-in water-driven loop with a translucent glass fibre wye, demonstrating that conventional pigs, spheres, welding bladders, and inspection vehicles would all pass though successfully. This bore design was used for Statoil's wyes, and has demonstrated itself to be reliably piggable in operation.

Testing programmes of wyes have also been carried out by BHRA at Cranfield and British Gas, believed to be 4 and 8-in scale model tests and full-scale pull-through tests of on-line inspection vehicles respectively.

Further research work has been carried out by Seanor Engineering AS for BP Norway as part of the BP diverless subsea production system (DISPS) project. Seanor developed compact 12-in convergent and divergent wyes for use in pigging flowlines from a platform to a template, around a crossover loop and back to the platform. These were successfully tested in the vertical on water, air and water/air mixtures. A preference for long-bodied (1.5D) cupped pigs was established. These DISPS designs have not yet been used in operation, but they form the ground work for future developments using active-diverter wyes and compact-converger wyes.

ADVANCES IN DESIGN APPROACH

The following paragraphs describe an enhanced approach recently adopted to produce economical designs for two large-diameter high-pressure wye pieces. The main areas addressed are pigability, pressure containment, and manufacture. Fig.4 illustrates the main features of the design.

Pigability

Pigability is a function of the profile of the internal bore. As detailed above, a great deal of research and development work has been carried out in this field, as a result of which the following features are incorporated:

- a) The angle between the branches is set at 30°. Sharper angles increase the length over which the bores merge, which would increase the probability of a pig coming to rest in the wye with the flow by-passing around it. Larger angles mean that the pigs have to turn more sharply into the outlet, with correspondingly larger impact forces and accelerations. Model tests indicate that 30° is the optimum angle.
- b) The bore in the section where the branches merge is enlarged to 105-110% of the pipeline internal diameter. This is large enough to allow the pigs to contact surfaces and expand out to their unrestrained diameter, hence reducing the friction on the pig as it passes through the wye.
- c) The region just before the exit bore is smoothly profiled with minimum radii of 5 diameters in the longitudinal planes. The reduction in bore is made gradually, over a distance of about one diameter.

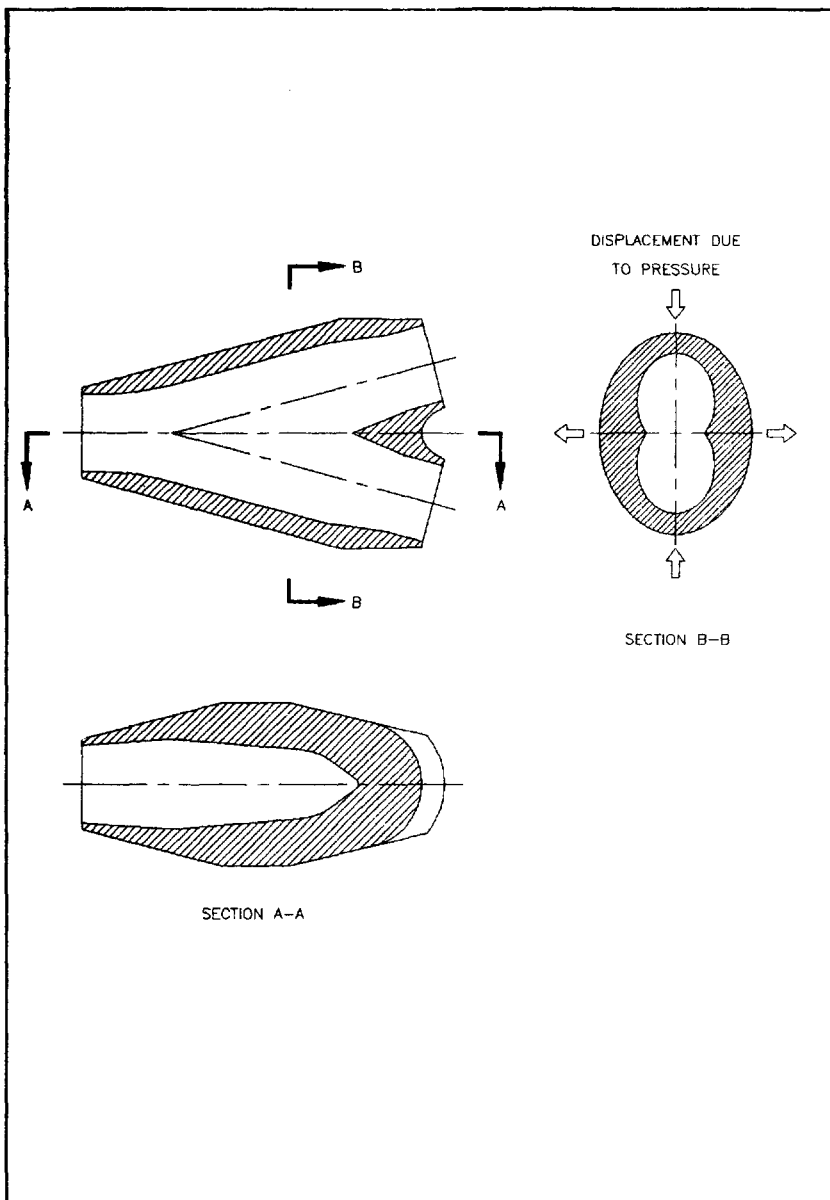


Fig.4. Streamlined wye design.

- d) The web between the incoming branches is kept as long as possible to maintain the separation between the bores. The crotch area, where high stresses would otherwise develop, is machined back and profiled locally.

Manufacture

Scoping calculations show that scaling up existing smaller-diameter designs leads to problems with high weights and thick walls. Fig. 5 shows a graph of predicted weight as a function of pipeline diameter for 2500psi pressure. Concerns are that the thicker walls would lead to high costs in manufacture, inspection and handling. The design illustrated in Fig. 4 is, therefore, adopted, with a smooth external profile and thinner walls suited to both forging and casting manufacture and to ultrasonic inspection. This approach also shows a considerable weight saving, as illustrated in Fig. 5.

FE analysis for operational loads

The behaviour of the wye under operational loads is determined using finite-element modelling. Pressure containment, loads from the branch pipework, and temperature differential stresses due to incoming streams at different temperatures, are evaluated. Stress and fatigue levels are kept within BS5500 allowables.

A full-PC version of ANSYS is used. Accounting for symmetry planes within the wye, a quarter model is generated comprising typically 1200 8-noded brick elements, as shown in Fig. 6. A minimum of three elements are used through the wall thickness. High stress gradients occur in the neighbourhood of the wye crotch, and the mesh is further refined in this area to evaluate the peak stresses.

The behaviour of the wye under pressure is to bend outwards at the elongated sections where the bores are merging, as shown in Fig. 6. The shape of the cross section is arranged to resist the bending with thicker central walls. This bending movement is also restrained at the crotch, which is consequently the most highly stressed region. FE analysis determined that it is necessary to cut back the area between the bores to relieve stress concentration. Under bending moments in the wye branches the stress intensifies in the outside of the crotch, which was shown to need reinforcement and a smooth profile. Stresses in the body of the wye were generally very low compared to code limits, which points to the potential for further design optimization.

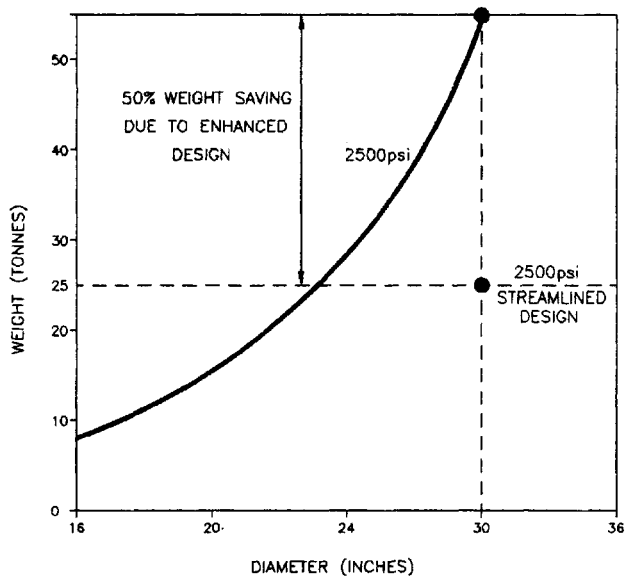


Fig.5. Weight predictions for wyes.

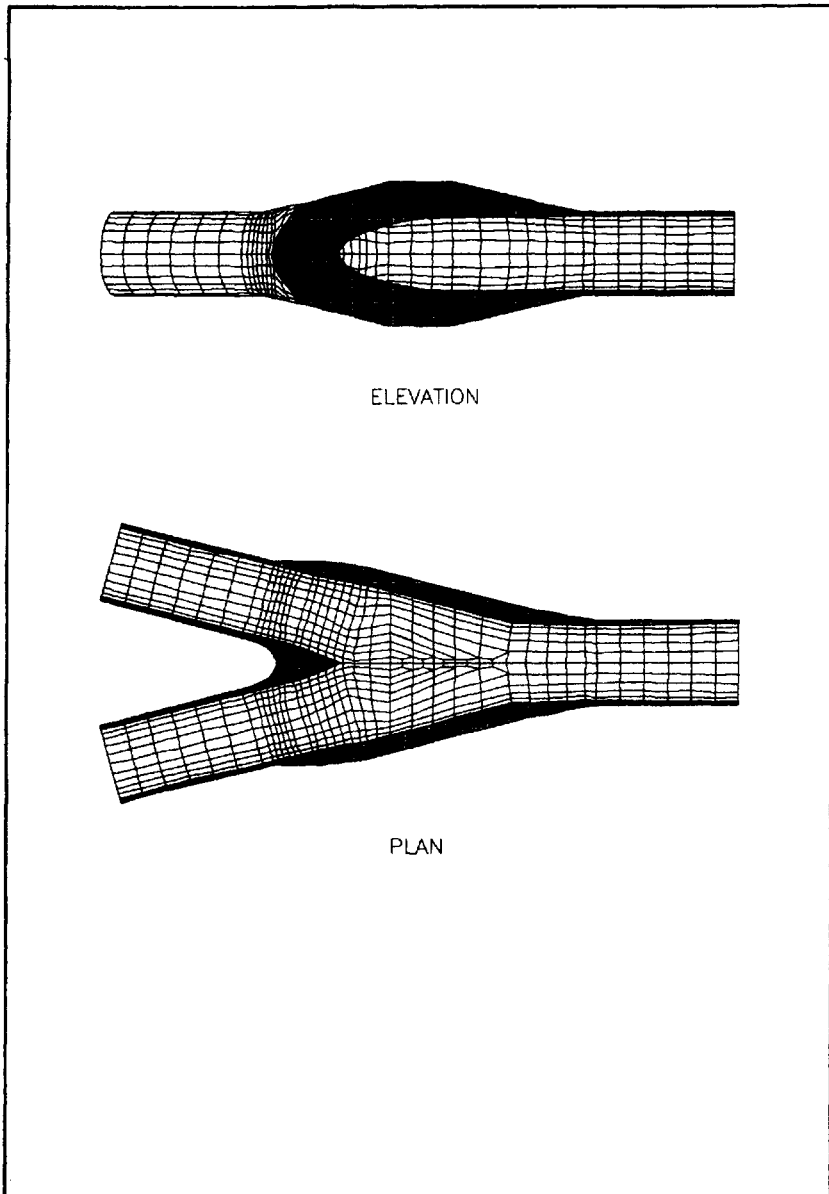


Fig.6. Finite element meshing for wye piece.

APPLICATIONS

The principal use for a wye is to connect two pipelines of the same diameter such that both can be pigged. Example applications are:

- a) connecting an entrant into a pipeline at its closest point so as to minimize the total pipeline length;
- b) inserting a wye at the base of a riser to tie-in a second entrant to the one riser, thus retaining the same number of risers and avoiding the expense of retro-fitting ones;
- c) combining a wye and subsea isolation valve installation;
- d) stacking wyes in series, always retaining a piggable inlet to the pipeline system for future entrants.

The alternatives to wyes are risers and tees. These are compared in the following sections. Table 2 sets out the broad areas of application for each. First of all, however, a characteristic arrangement for a wye junction (Fig.7) is considered. This would be adapted to suit a particular job, but serves to illustrate a few points as follows.

The offset layout shown in Fig.7 is mainly a function of the installation method. Typically, the main pipeline would be installed with a flanged spool. The wye, valves and protection frame, which would be too big to be laid in

Junction type	Entrant line size	Pigging requirement
tee	smaller	infrequent
riser	smaller	routine
wye	same	infrequent or routine
none: lay another trunkline	larger	infrequent or routine

Table 2. Main applications for riser, wye and tee junctions.

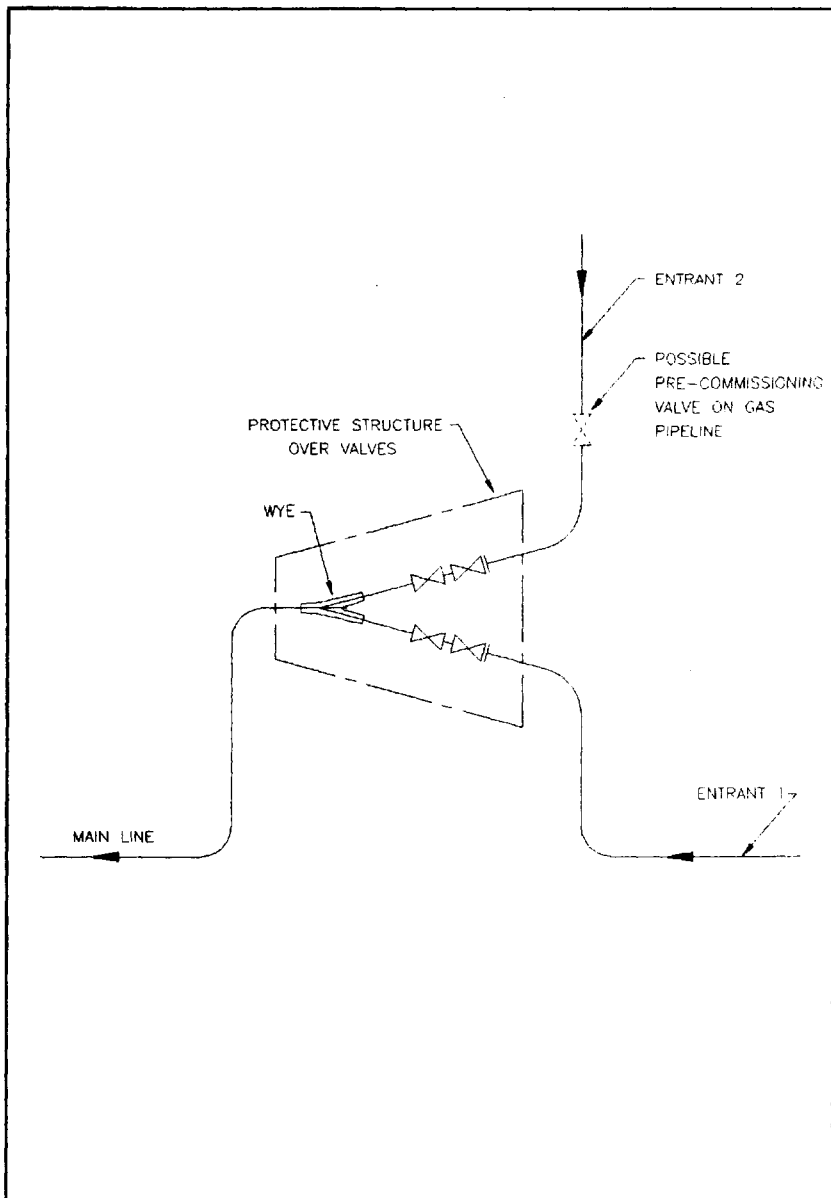


Fig.7. Typical arrangement for wye junction.

line, would be installed next to it. The pipeline spool would be removed and replaced by dogleg spoolpieces to tie in the wye. The pipeline system would then be leak tested and pre-commissioned.

The two valves on each branch allow either branch to be isolated whilst the rest of the pipeline system is operational. This function could be used, for instance, during a pipeline repair, for tying-in another pipeline, decommissioning a branch line, or pressure testing an ESD valve. It is always worth considering, however, whether all the valves are strictly justifiable.

At a later date the entrant pipeline would be installed and connected to the spare branch. In the case of a gas line, it would normally be dewatered to a pre-commissioning valve, a spoolpiece would be connected across to the wye, tested and blown down, and the entrant pipeline dried prior to commissioning. An entrant to an oil system could avoid the extra pre-commissioning valve by testing against the wye valves and dewatering back to the platform. Again, there are many variations on this depending on the relative timing of the main pipe, wye and entrant pipe installations.

WYE vs RISER CONNECTION

The main alternative to a wye junction is to connect the second pipeline via a riser. Fig.8 compares the field configurations resulting from wye and riser tie-ins. Several advantages and a few disadvantages arise from having the wye as opposed to the riser as discussed below. First the advantages:

Safety: as can be seen from Fig.8, the wye junction eliminates the need for an additional import riser on the platform, and is thus a safer solution from the viewpoint of the platform, particularly for gas pipelines.

Field layout: The wye junction can be sited away from the platform avoiding seabed congestion around the platform. This leaves the field free to be developed using satellite wells and flowlines, for example, without being crowded by incoming pipelines from other fields. It also allows the field layout to be planned with greater certainty, keeping pipelines and flowlines in corridors with safe anchoring areas between, avoiding spoolpieces under boat-loading areas, etc.

Cost: The wye will normally show cost advantages over a riser, particularly if the riser has to be retro-fitted, or a cantilever extension has to be added for the pig receiver. If, however, the wye has to be retro-

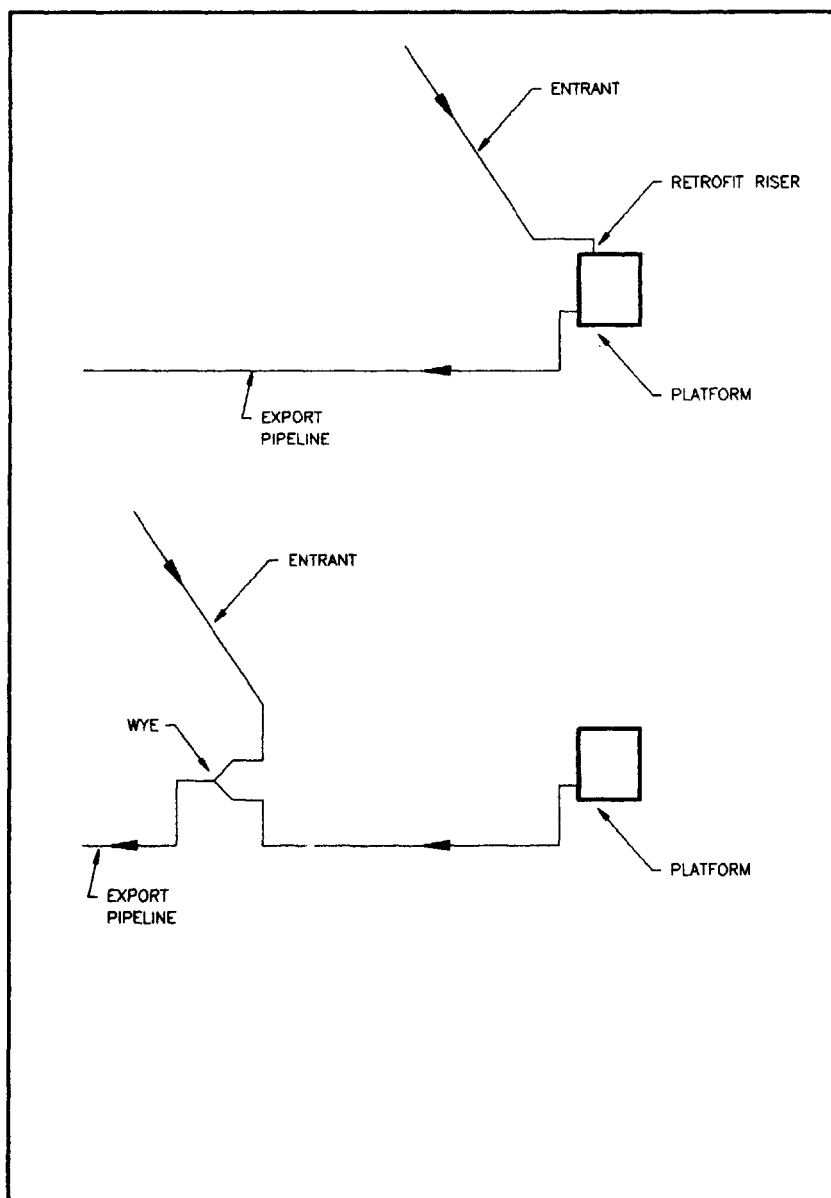


Fig.8. Comparison of riser and wye tie-ins.

fitted in an existing pipeline, then the costs could go either way, depending amongst other things on the pipeline lengths, the duration of the required shut down, and any penalty associated with making the new line the same size as the existing.

Tie-in: Tying-in at a wye can be done without shutting down the existing system. This has recently been demonstrated by the *Gyda* tie-in. In comparison, construction work on a platform to tie-in an entrant is likely to be more disruptive.

End of field life: If import risers are used and the original field is depleted before the end of the pipeline life, it would need to be maintained as a riser platform, or a subsea junction inserted. Using a wye junction allows the original platform to be isolated and decommissioned without affecting the rest of the pipeline users.

Emergency shut down: If import risers are used and there is an emergency shutdown on the platform, the upstream fields will also have to be shut down, whereas a wye junction would keep them operating independently.

Shorter line: A wye junction can be placed to give the entrant the shortest pipeline route. This is particularly so for a retro-fitted wye.

Wye junctions also have some drawbacks, and are by no means always the best solution for tying-in an entrant. The main drawbacks are as follows:

Same size line: The wye junction's main use is to connect entrants of the same size as the original pipeline. Whilst it is possible to connect other sizes, these would not be piggable. There is typically a cost and technical balance for an entrant between having, say, a smaller non-piggable line to a tee, a larger piggable line to wye, or a longer piggable line to a riser.

Subsea valves and protection covers: It would be feasible to have a wye without valves. However, they are normally an operational requirement. For example, to tie-in an entrant without affecting the rest of the system would normally need two valves on the branch of the wye to give double-block-and-bleed isolation. For this reason, most wyes to date have two isolation valves on each branch. If subsea valves are used, it is necessary to have a protection cover.

Reverse pigging: Whilst not normally required in operation, it is sometimes desirable to be able to pig in reverse during commissioning, for example in dewatering a line from the shore to the platform. This would cause technical problems at a wye junction which is only piggable in the convergent directions, and would require some form of deflector plate for reverse pigging.

Recent advances in piggable Y design

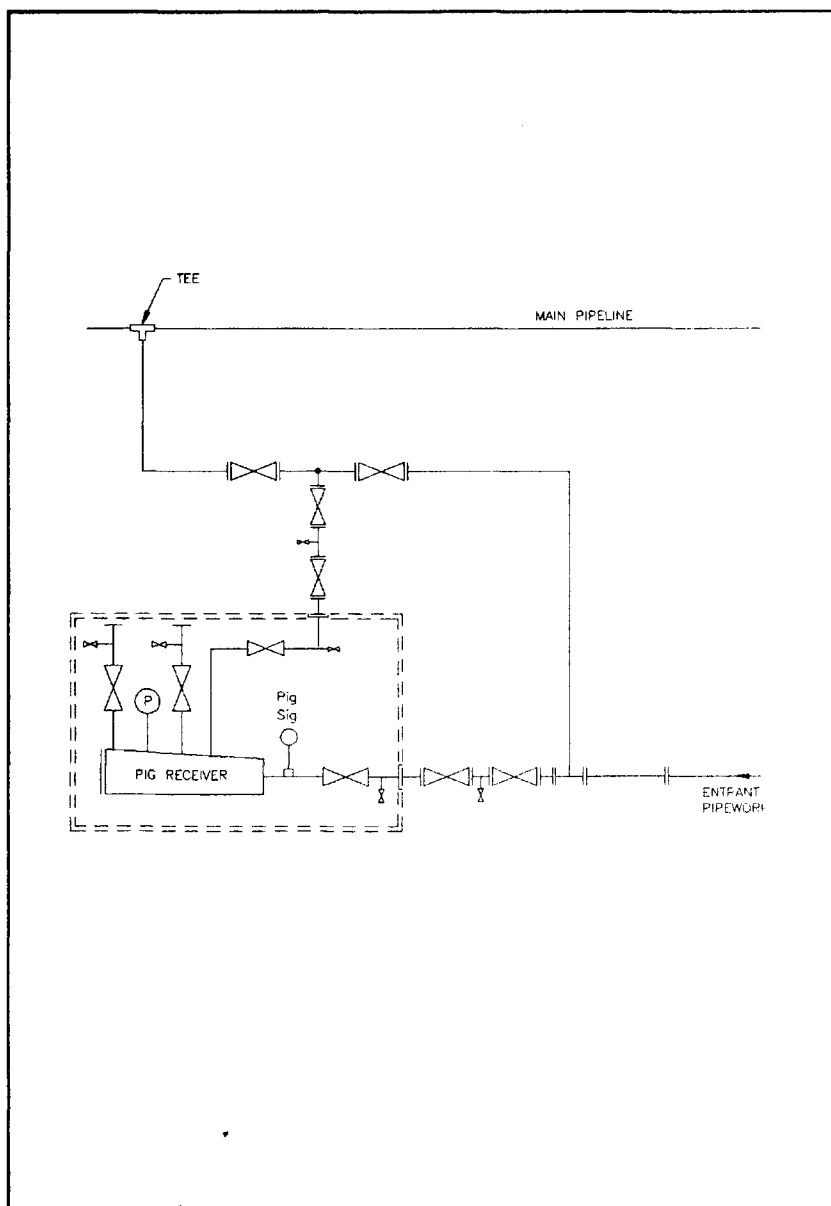


Fig.9. Retrievable subsea pig trap.

Flow limitations: To ensure the passage of pigs through the wye, there has to be adequate flow in the main line and no reverse flow in the branch. For a pipeline system which needs periodically to be coated by a slug of corrosion inhibitor held between two batching pigs, there may be limitations on the flow conditions at the wye to avoid loss of inhibitor up the second branch.

WYE vs TEE

Tees normally have the advantage of being relatively small and light such that they can be laid with the pipeline and need only a small protection cover. Their main application is for tying-in smaller-diameter pipelines. They are not readily piggable and would require specialist techniques such as gel or foam slugs, or a subsea pig trap.

Fig.9 illustrates a subsea pig trap for a gas pipeline. The deployment, operation and retrieval of this device would be a costly exercise unsuited to routine pigging. It could, however, be justified for intelligence pigging.

Overall, the applications of wyes and tees are quite distinct, in that wyes are suited to a same-sized piggable entrant, and the tee to smaller, rarely-pigged entrants.

CONCLUSIONS

a) The technology for designing and manufacturing piggable wyes is now maturing. This paper details the features to ensure that the junction is reliably piggable, operates within allowable stress levels, and can be manufactured.

b) A successful operational track record for wye junctions has been built up in the North Sea, and they are now being used in increasing numbers.

c) Wyes provide an alternative to import risers for the connection of other fields to a pipeline system, and in many cases will show cost and safety advantages both in installation and operation.

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PIGGING CHARACTERISTICS OF CONSTRUCTION, PRODUCTION AND INSPECTION PIGS THROUGH PIGGABLE WYE FITTINGS

RESULTS OF pigging tests are presented for various construction, production and inspection pigs which demonstrate their pigging characteristics while passing through a 10in x 10in x 10in piggable wye fitting. Detailed results are presented for inflatable and soluble spheres, a dual-diameter scraper pig, squeegee(cup-type) pig, foam pigs, dual-diameter gauging pig and an intelligent pig. Details of the test facility, procedures, and data-reduction techniques are also presented and discussed.

INTRODUCTION

Piggable wye fittings used for high-pressure, underwater pipeline applications were introduced in the North Sea nearly ten years ago. Since then, other areas such as the Gulf of Mexico, Adriatic Sea and Middle East have also seen applications. The main reason for using piggable wye fittings is to allow lateral connections to trunklines that can be pigged from either the lateral side or through the trunkline.

There are several reasons for designing a piggable lateral connection. For oil pipeline applications, the main interest has been to allow scraper pigs to be used where accumulated paraffin deposits can lead to plugging of the lateral pipeline. For gas or two-phase liquid/gas transmission applications, the interest is usually to allow running pigs for removal of liquids that increase pressure losses or cause internal corrosion. There is also a growing interest in the use of inspection pigs that can be used to examine the lateral pipeline.

Prior to the introduction of piggable wye fittings, on many gathering systems it was necessary to bring the pipeline to a platform, up a riser and into

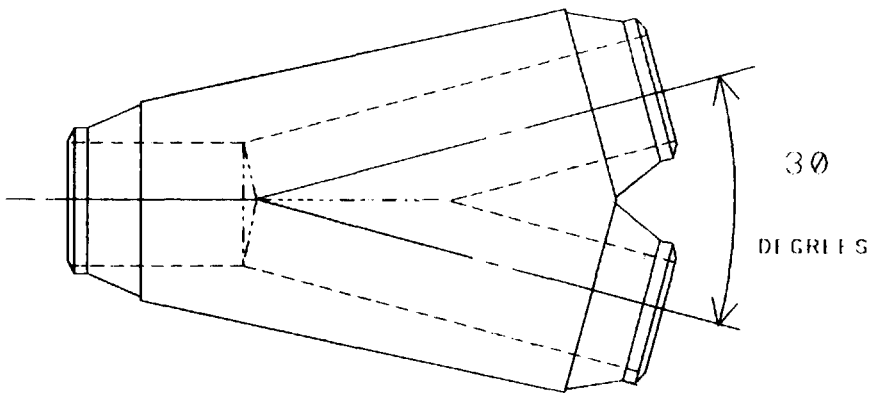


Fig.1. Symmetric piggable wye.

a pig receiver. The product was then inter-connected with another pipeline and a launcher was used to allow the next segment of pipeline to be pigged. In some instances, the sole purpose of the platform and risers is to allow two pipelines to be inter-connected while maintaining the piggability of both pipelines. One of the biggest future uses for piggable wye fittings will be the elimination of such high-cost facilities associated with gathering systems.

The feasibility of manufacturing piggable wye fittings for high-pressure applications is now well established. However, there has been very little information published relative to the performance of typical construction, production and inspection pigs required to pass through piggable wye fittings. The availability of such performance data on the characteristics and limitations of piggable wye fittings will be useful for designing and evaluating future applications.

The results presented in this paper give quantitative performance characteristics for the following specific pigs:

1. TDW *Redskin* foam pig
2. Knapp Polly Pig foam pig
3. F.H.Maloney inflatable sphere
4. Select Industries soluble sphere
5. TDW dual-diameter (14 x 10) scraper pig
6. Knapp Polly Pig dual-diameter (14 x 10) gauging pig
7. S.U.N.Engineering squeegee (cup-type) pig
8. VetcoLog intelligent pig

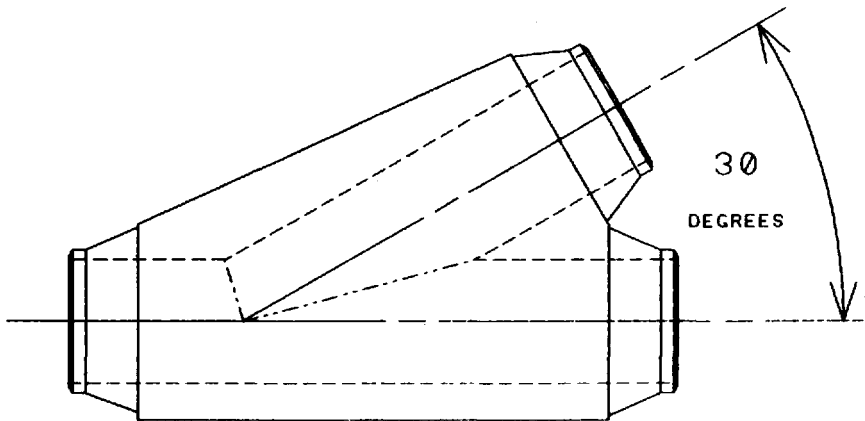


Fig.2. Non-symmetric piggable wye.

Qualitative results are also presented and discussed in relation to general observations and pigging characteristics that may be useful in designing and/or operating pipeline systems with piggable lateral connections. Design of the piggable wye fitting as a pressure vessel and structural element of the pipeline system is not within the scope of this work; that topic has been discussed previously[5].

GEOMETRY CONSIDERATIONS

Several types of internal geometries have been proposed for high-pressure, forged piggable wye fittings. The symmetric wye geometry is shown in Fig. 1; in a symmetric wye, the inlets are located symmetrically relative to the outlet. This geometry minimizes the angular turn that a pig has to make as it passes through the wye fitting. Another type of internal geometry that has been considered for high-pressure, forged piggable wye applications is the non-symmetric geometry, shown in Fig. 2, which has the advantage that pigs passing through the straight run do not have to negotiate a turn. However, pigging through the lateral inlet requires negotiating an angle that is twice as severe as for the symmetric wye fitting for a given angle between inlets.

It should be noted that several other geometries have been used for fabricated wye fittings. For example, Ref. 6 describes a 12-in application for

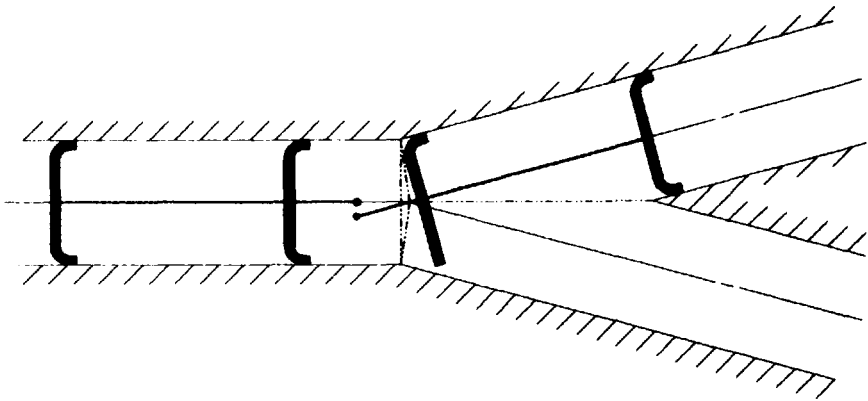


Fig.3. The 'nose-dive' phenomenon.

a piggable lateral connection used in the Adriatic Sea. The information presented herein will strictly relate to forged wye fitting configurations.

In both the symmetric and non-symmetric wye configurations, the length of the crotch opening is approximately:

$$L = \frac{sD}{\sin(a)}$$

where (D) is the inside diameter of the wye fitting and (a) is the angle between inlets.

The length of the crotch opening is an important design consideration for a piggable wye fitting. This length effectively defines the distance required between seals to prevent a by-pass condition that could stall the pig inside the wye fitting. Generally, selection of the angle (a) involves some trade-offs. For example, reducing the angle between inlets will decrease the magnitude of the turn that must be negotiated by the pig, so it tends to be viewed as improving the pigging geometry. However, the length of the pig may have to increase to avoid a by-pass condition and, therefore, there may be no improvement, or in fact a reduction in piggability. Moreover, the longer crotch opening generally leads to higher stresses in the fitting, which adds to the cost of the wye fitting. In general, for any given application, selection of the angle between inlets should be made taking into consideration the particular types of pigs to be used as well as the overall cost of the fitting.

The angular turn associated with the piggable wye fitting gives rise to a phenomenon known as "nose-diving". Fig.3 shows a typical dual-module pig passing through a wye fitting; when the front module is fully in the outlet section and the rear module is still located in the inlet section, there is a significant bind on the connecting joint between the two modules. This is encountered because the rear portion of the front module tends to centre itself coincident to the axis of the outlet, while the front portion of the rear module tends to centre itself coincident to the axis of the inlet. This action results in the connecting joint being pulled in different directions, and causes the seal loads and resulting frictional drag to increase as the rear module approaches the outlet. Although this is similar to the problem of pigging through a mitred joint, there are several distinct differences. First, the presence of the crotch opening has the effect of reducing some of the seal compression, and hence the drag forces on the pig. Secondly, the rear module can move slightly toward the centre of the wye, further reducing the frictional drag. The net increase in frictional drag loads associated with the "nose-dive" phenomenon is one of the main reasons for differential pigging pressures to increase inside the fitting on multiple-module pigs. It should be noted that the "nose-dive" phenomenon is sensitive to the magnitude of the angular turn made by the pig and, therefore, is worst on non-symmetric wye geometries.

A considerable number of pigging tests have been conducted to evaluate the operational performance and pigging characteristics of various types of pigs passing through a wye fitting geometry. For the test results presented herein, a nominal 10in x 10in x 10in symmetric fitting was used with a 30° angle between inlets. A symmetric configuration was selected because several dual-module pigs were to be tested. Based on geometric considerations and studies with scaled models[5], it was believed that loads on the connecting joints would be unacceptable if a non-symmetric configuration was used.

PIG-TESTING FACILITY

A pigging facility was designed and built to test various types of pig under a wide range of flowing conditions. The pigging facility is illustrated schematically in Fig.4. It was decided to use compressed air to pressurize a water tank and generate flow, rather than a conventional approach using pumps. This was done because very high flow rates (in excess of 50,000brl/day) could be achieved for short periods at relatively-low cost. Also, the system could be adaptable for gas tests using air rather than water. A

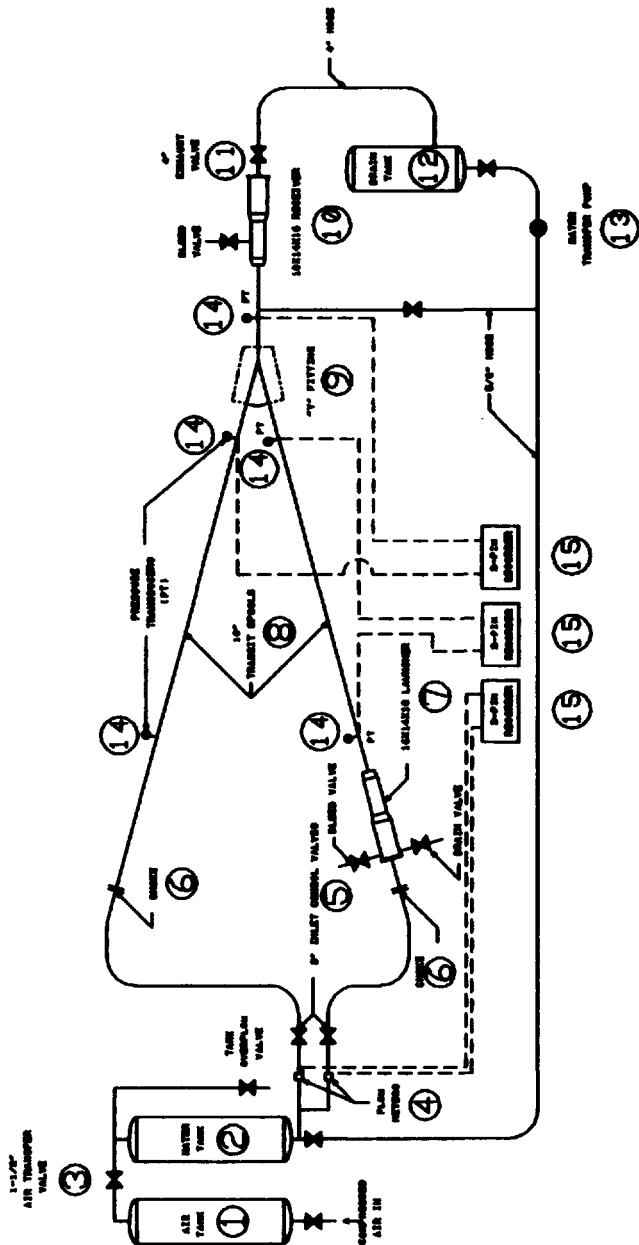


Fig.4. Pig-testing facility schematic.

Pigging through Y fittings

photograph of the test facility is shown in Fig.5. The test facility included the following items:

1. air tank: steel tank with approximately 500gall capacity used to store compressed air;
2. water tank: steel tank with approximately 600gall water capacity. The water was drained from the tank and the extra capacity was used to store compressed air during gas tests;
3. air valve: a 1½-in valve used to transfer air pressure to the water tank;
4. flow meters: turbine flow meters with 600gpm capacity used to measure flow on each side of the wye;
5. inlet control valves: 3-in ball valves used to control flow from the water tank into the transit spools;
6. chokes: chokes used to stabilize flow and regulate distribution between transit spools (individually sized for the particular flow conditions desired);
7. launcher: a 16-in (nom.) barrel, concentrically reduced to 14in (nom.) and further concentrically reduced to 10in (nom.);
8. transit spools: approximately 20-ft long spools of 10-in pipe to allow pigs to accelerate and reach a reasonably steady velocity before entering the wye fitting;
9. piggable wye fitting: a 10in x 10in x 10in symmetric piggable wye fitting;
10. receiver: a 10in x 14in x 16in barrel using concentric reducers to transition diameters;
11. exhaust valve: a 4-in ball valve used to start and stop flow during water tests;
12. drain tank: Steel tank with approximately 750gall water capacity;
13. Transfer pump: electric pump used to transfer water from drain tank to water tank or piping;
14. pressure transducers: used to measure pressure at strategic locations during pigging tests;
15. recorders: three 2-pin recorders used simultaneously to record flow rates (two each) and pressure readings (four each).

During typical water-driven pigging tests, there were three 2-pin recorders used to make a record of pressures and flow rates vs time. One 2-pin recorder was used to plot the flow rate in each side of the wye; a second 2-pin recorder was used to plot the upstream and downstream pressures in the transit spool on the side which contained the pig or pig train. The third 2-pin recorder was used to plot the pressure on the outlet side of the fitting and the downstream

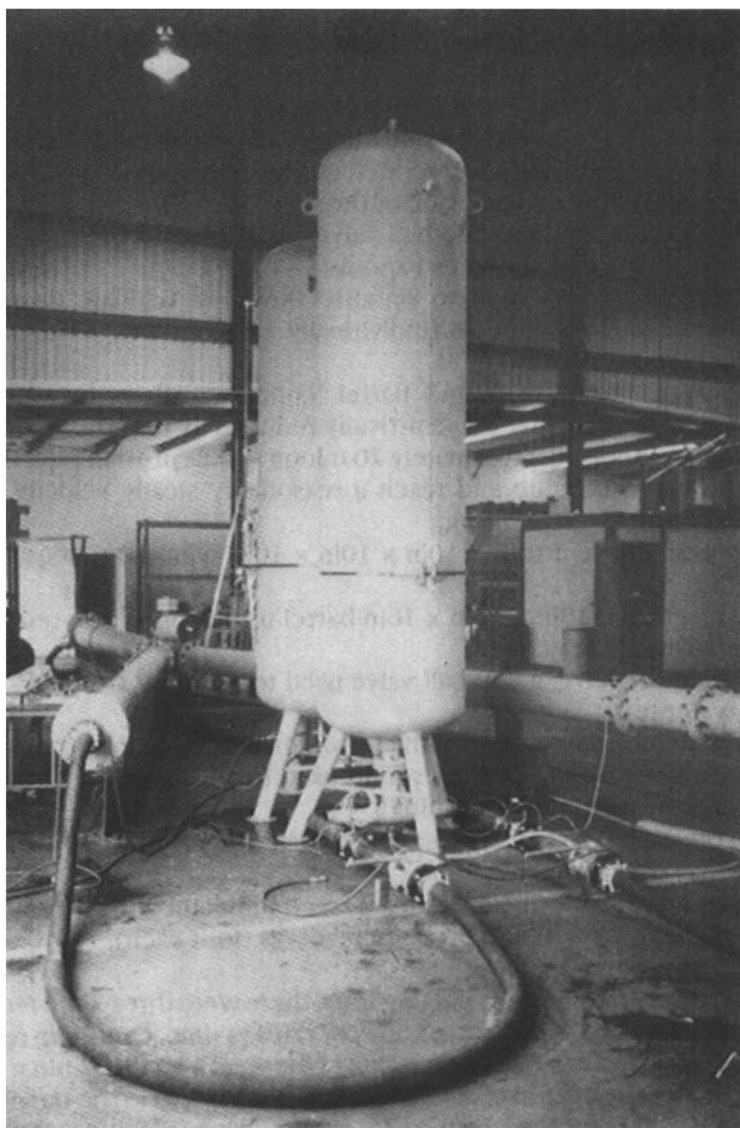


Fig.5. The pig-testing facility.

Pigging through Y fittings

side of the transit spool on the opposite side, i.e. the side opposite to the transit spool containing the pig or pig train.

The three 2-pin recorders were attached to a synchronizing device which marked each chart, so that events could be measured relative to some initial time. The pressure transducer measurements were found to be excellent pig signallers in addition to being used to measure the differential pigging pressures. This signalling feature allowed location of the pigs which, coupled with the relative time and knowledge of the geometry, allowed direct computation of average pig velocity between known positions.

The instrumentation was modified somewhat for air-driven pigging tests. Since the flow meters were not usable for air tests, four pressure transducers were used in the transit spool used to pass the pig (two each on two 2-pin recorders). The additional pressure readings in the transit spool allowed calculation of a velocity profile rather than an average velocity, which is useful due to the greater difficulty in conducting pigging tests with gas. The other two pressure transducers were used to record the pressure on the outlet side of the wye and the air tank pressure.

The tank pressure vs time curve was used to approximate the air flow rate out of the tanks. This was done by determining the rate of change of tank pressure with time. The flow rate is then calculated as:

$$\text{Flow rate} = \frac{V}{14.7} \times \frac{dp}{dt}$$

where V is the volume of the two tanks (air and water) and the rate of change of pressure with respect to time was determined using finite difference techniques with the data from the tank pressure vs time chart. It should be noted that the flow rate is not particularly useful in characterizing pig performance under conditions of compressible flow. Generally, the velocity and differential pigging pressure are more useful parameters and better characterize pig performance.

TEST PROCEDURES

For water-driven pigging tests, the following basic procedures were followed:

1. The air tank was pre-charged to the desired pressure (charging pressure varied between 50-125psi depending on the flow rate).

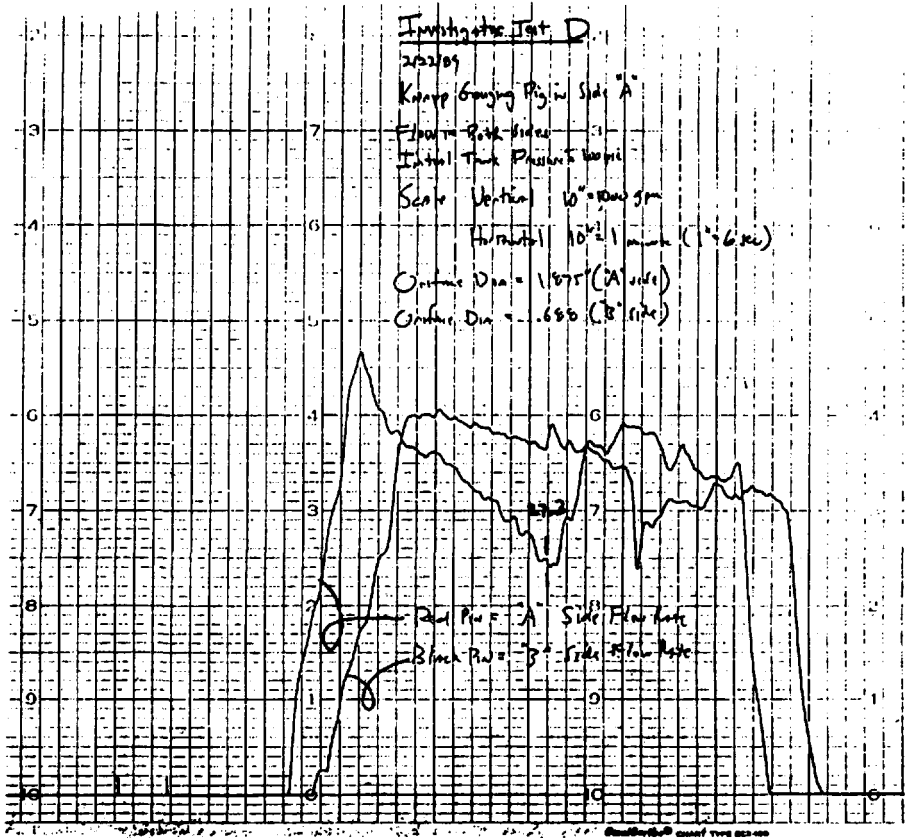


Fig.6. Flow rate vs time.

2. The water tank was filled and pressure was applied by opening the transfer valve (control valves were closed, so only the air tank and water tanks were pressurized).
3. The pig or pig train was installed in the launcher and the piping was filled with water.
4. The appropriate control valve or valves were gradually opened, causing the piping to reach equilibrium with the tank pressure (no appreciable flow occurs since the exhaust valve is closed).
5. The recorders were started and synchronized.
6. Flow was initiated, launching the pig or pig train by opening the 4-in exhaust valve.

Pigging through Y fittings

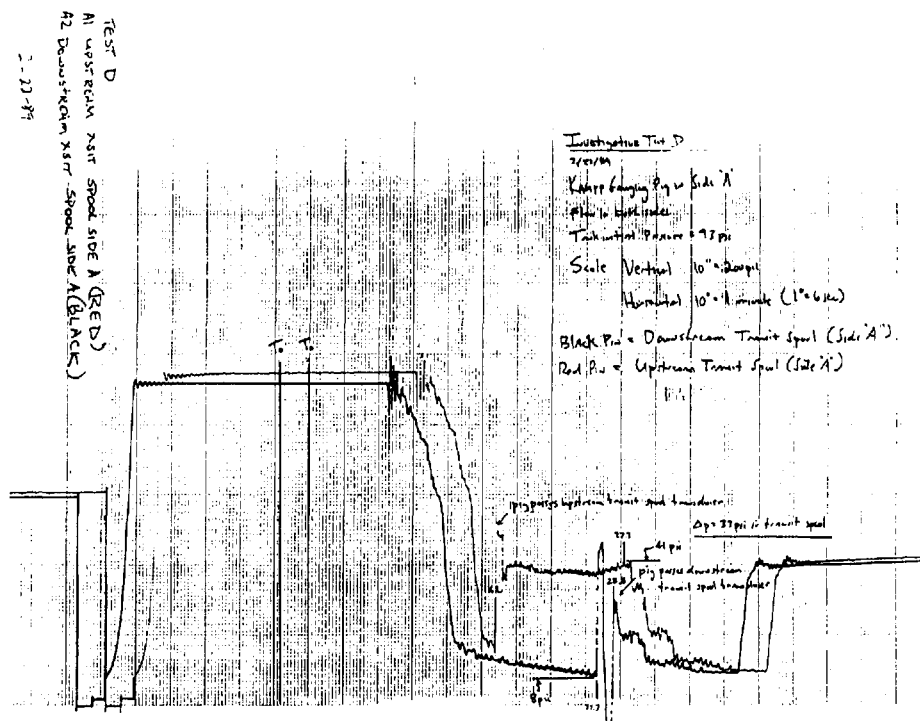


Fig.7. Upstream and downstream transit spool pressure vs time.

7. The downstream pressure reading was monitored to indicate passage of the pig. After pig signal is received, flow was allowed to continue for approximately 5-10 seconds to ensure that the pig travelled into the receiver.
8. The 4-in exhaust valve was closed causing flow to terminate.
9. The 3-in control valves were closed, the piping is depressurized, and drained, and the pig or pig train was removed from the receiver.

For most tests, the inlet chokes were sized and the initial tank pressure was selected to achieve the desired flow rates, i.e. pig velocity. For very low flow rates (less than 150gpm), the appropriate 3-in control valves were manually operated with feedback from the flowmeter readings to control the flow rate.

Figs 6, 7 and 8 demonstrate typical results for a water-driven pig test. Fig.6 is a recording of the flow rate during a test using a Knapp Polly Pig dual-diameter (14 x 10) gauging pig. Fig.7 shows the upstream and downstream

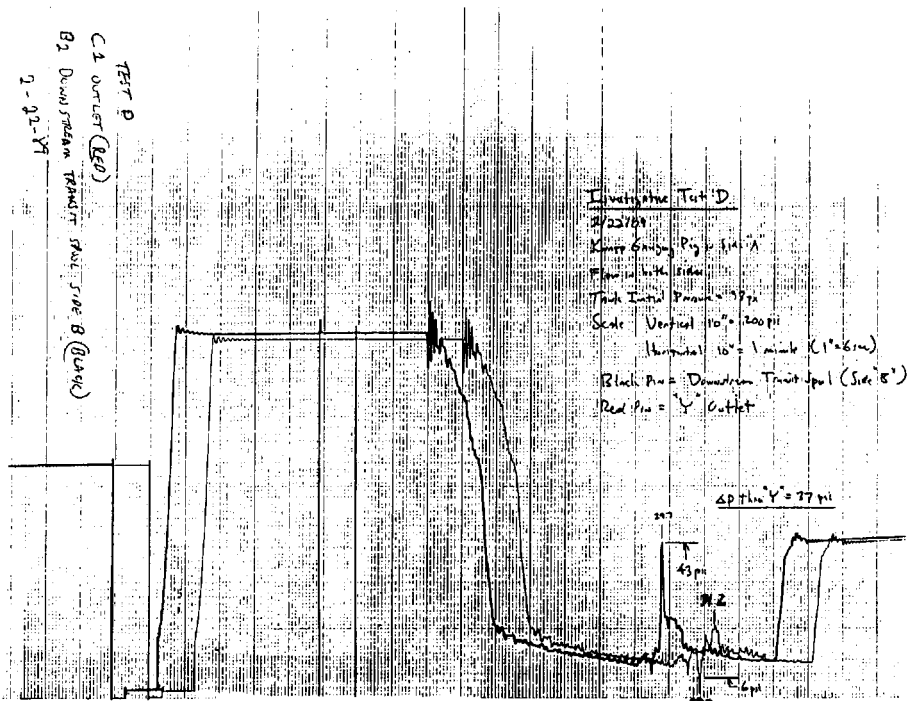


Fig.8. Outlet and downstream transit spool pressure vs time.

pressures in the "A" side transit spool, i.e. the side in which the pig was installed. Fig.8 shows the pressure downstream of the fitting and the pressure at the downstream end of the "B" side transit spool, i.e. the pressure near the inlet to the wye on the side opposite to the pig.

The following example illustrates the techniques used to reduce data in a typical water-driven test such as those presented in Tables 2 through 8 (see pages 404-413). Referring to Figs 7 and 8, it is seen that after the exhaust valve is opened, the pressures at all four locations begins to drop rapidly from the initial (tank) pressure of approximately 93psi. Fig.7 shows a pressure increase at 16.2secs (relative to the synchronization mark - T_0) which indicates that the pig has reached the pressure transducer. The pressure then stabilizes, indicating the pig has fully passed the transducer. Referring again to Fig.7, it can be seen that the upstream pressure transducer reading is reasonable steady after the pig passes, and varies between 38 and 41psi until some time slightly past 27.3secs. The downstream pressure transducer reading contin-

Pigging through Y fittings

ues to drop until 27.3secs, indicating that the front portion of the pig has just reached the downstream pressure transducer location. It should be noted that after the back end of the pig passes the downstream pressure transducer, both pressure readings in Fig.7 should be identical. Using dividers, one can compare the two pressure charts starting from the right end and moving leftward until a difference in readings is observed. This occurs at 28.8secs. Therefore, the time required to travel down the transit spool is 12.6secs (28.8 minus 16.2). The average velocity is then calculated by dividing the distance between transducers (18.75ft) by the travel time. Hence, the average velocity is 1.49ft/sec. The average flow rate can then be calculated by multiplying the average velocity by the flow area inside the pipe.

It should be noted that the error in the above technique is generally related to the length of the pig, since it is often difficult to determine if the entire pig is past the pressure transducer or just a portion of the pig. This is particularly evident for long pigs with multiple seals.

Referring again to Fig. 7, it is seen that the peak differential pigging pressure occurs at 27.3secs when the upstream pressure is 41psi and the downstream pressure is 8psi. Hence, the peak differential pigging pressure is 33psi while the pig is in the transit spool.

Reviewing the flow rates in Fig.6 shows that the flow rate in both sides increases after the exhaust valve opens. The flow rate on the side with the pig (the "A" side) reaches a peak at approximately 470gpm and then gradually decreases as the pig travels down the transit spool. At the point where the pig reaches the wye fitting, the flow rate on the "A" side has dropped to approximately 240gpm. Over the same period the flow rate in the opposite side (the "B" side) remains reasonably steady between 370 and 400gpm. As the front of the pig enters the fitting (just after 27.3secs), the flow rate in the "A" side increases to approximately 360gpm. This behaviour is typical for most types of pigs, and is attributable to filling (pressurizing) the opposite side transit spool ("B" side), increased flow by-pass and, in many instances, an increase in pig velocity while inside the fitting.

Referring to Fig.8, it can be seen that the "B" side down-stream pressure falls after the exhaust valve is opened, and continues to drop until 29.7secs. The pressure spike at 29.7secs indicates the front of the pig has entered the wye. After the pig is completely past the pressure transducer on the downstream side of the wye, the two readings in Fig.8 should be identical. Hence, the charts can again be compared, starting with the right hand side and working to the left to locate where the curves start to differ. In this case, it is found that the curves differ at times prior to 31.2secs. Therefore, at 31.2secs, the pig is completely in the outlet. Also, by inspection, the peak differential pigging pressure while the pig is in the fitting can be determined. In this case,

the peak differential pressure occurs at 29.7secs, and is the difference between the inlet side ("B" side) pressure of 43psi and the outlet pressure of 6psi, i.e. 37psi.

It should be noted that measurement errors are possible in several parts of the above procedure. First, there are small differences between pressure transducer readings. For example, comparison of the pressure readings at the start and end of the test shown in Figs 7 and 8 demonstrates as much as 3psi difference in readings at different locations. Measurement of transit spool average velocity (and average flow rate) also has errors associated with judging whether the front end or rear end of the pig is at the transducer location. Hence, the location error could be in the order of magnitude of the pig length. In some tests this is significant, since several of the pigs were over 4ft long (more than 20% of the separation distance between transit spool transducers).

Although the quantitative results will clearly have some associated error, it should be understood that the most important observation and, in fact, the main objective for most tests, was to verify that the pig or pig train would successfully pass through the wye without damaging the pig or the fitting. The flowing conditions, average pig velocity and differential pigging pressure serve primarily to describe the pigging conditions. It is generally believed that the pressure measurements are within ± 4 psi throughout all tests. The error in average velocity (and average flow rate) in the transit spool will be greatest on the long pigs (TDW dual-diameter scraper pig, VetcoLog intelligent pig, and the pig trains involving the TDW dual-diameter scraper pig), and could be as high as 25%.

RESULTS

The results of the pigging tests are summarized in Table 1 (page 404). The various pigs are ranked by the differential pigging pressure from lowest to highest. The small, light, single-module pigs such as the foam pigs and spheres demonstrated the least pigging differential pressure required. The larger, dual-module pigs such as the Knapp Polly Pig dual-diameter (14 x 10) gauging pig, TDW dual-diameter (14 x 10) scraper pig and VetcoLog intelligent pig, required significantly higher differential pigging pressures.

It can be seen that a considerable range exists in the differential pigging pressures recorded for any particular type of pig. There are several important factors that account for these variations. First, the results presented are an accumulation of data from three different test programs performed as part of

Pigging through Y fittings

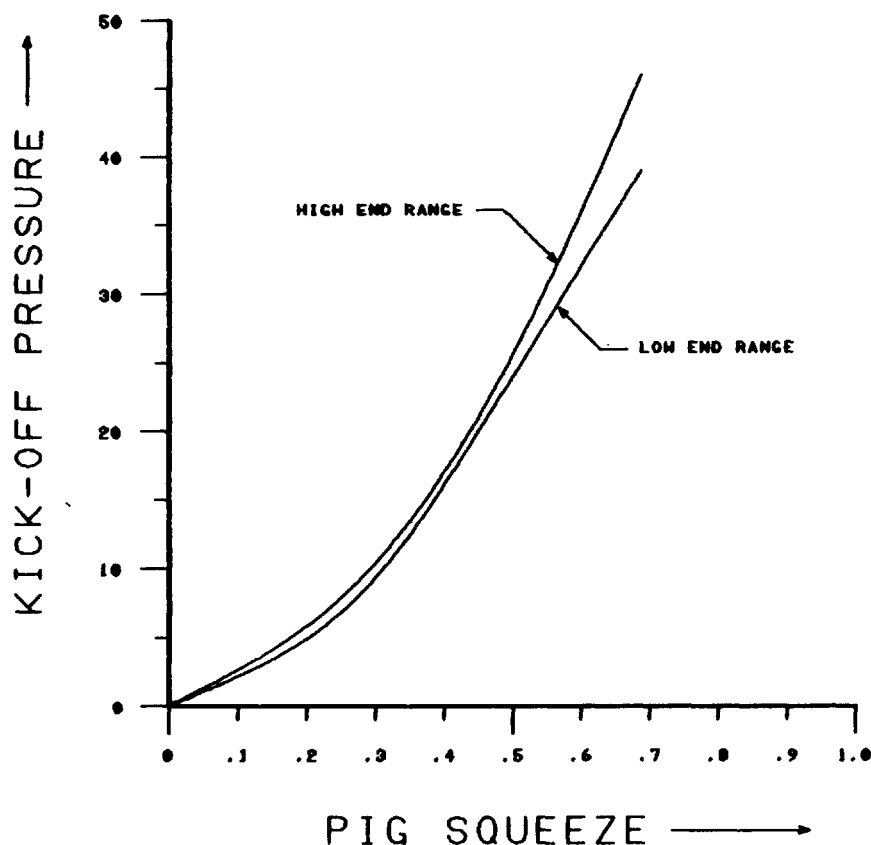


Fig.9. Kick-off pressure vs pig squeeze for F.H.Maloney sphere.

the Conoco Joliet project, one test program performed for Transcontinental Gas Pipe Line Corporation, and one performed by HydroTech Systems. Throughout these tests, subtle changes occurred in the ID of transit spools, that can have an effect on the differential pigging pressure. The sensitivity of pigs to changes in pipe ID is demonstrated in Figs 9 and 10. These results show that differential pigging pressures for an F.H.Maloney sphere and a S.U.N.Engineering squeegee (cup-type) pig are affected dramatically by the squeeze on the pig. Some of the pigging tests also had the presence of lubrication effects which reduces the required differential pigging pressures.

Results of testing for specific pigs are presented in Tables 2 through 11. Tables 2 through 8 show results for tests conducted using water, while Tables

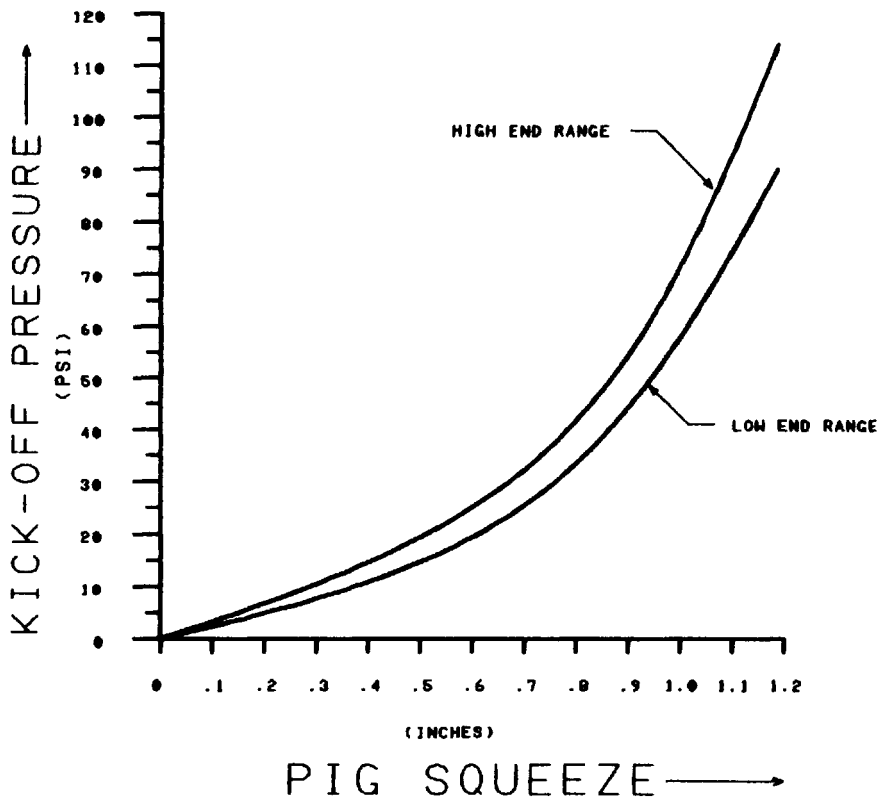


Fig.10. Kick-off pressure vs pig squeeze for S.U.N.Engineering 'squeegee' cup-type pig.

9 through 11 show results for air-driven tests. For the water-driven tests, the individual test results list the peak pigging differential pressure observed in the transit spool and through the wye fitting along with the average velocity of the pig in the transit spool, the average flow rate while in the transit spool, and the flow conditions in the opposite side. The air-driven tests show similar conditions, except the peak differential pigging pressure in the fitting is not listed. As mentioned previously, the recorder used for the outlet pressure transducer for air tests also recorded the tank pressure, rather than the inlet pressure on the opposite side. This prevented the comparisons done for the water-driven tests to directly measure the differential pigging pressure in the fitting. The results for individual pigs (Tables 2 through 11) are presented in order of increasing velocity.

Pigging through Y fittings

All of the pigs successfully passed through the symmetric wye geometry without problem. None of the pigs were damaged as a result of the excursion through the wye fitting and no damage was observed to the fitting during any of the tests. The pigs demonstrated several consistent performance features as follows:

1. The peak pigging differential pressure in the fitting was generally less than that encountered in the transit spool when medium to high flow conditions occurred in the opposite side and the pig was travelling at speeds greater than 1.35ft/sec. This "flow assist" effect appears in all of the pigs that were tested.
2. At low pigging speeds, i.e. less than 1.35ft/sec, the peak differential pigging pressure in the wye appears to increase when medium to high flow occurs on the opposite side.
3. At high pigging speeds, the short, light, single-module pigs pass through the fitting without difficulty and generally require less peak differential pigging pressure in the wye than in the transit spool.

In addition to the test results presented in Tables 2 through 11, stall tests were also performed on each type of pig. In the stall tests, the pigs were positioned in the wye fitting by pigging very slowly until a by-pass condition was observed. Flow was then increased, and in each case the pigs moved freely through the fitting and through the outlet without incident. Several pigs were checked for stall characteristics using gas (air). It was found that for the three pigs tested, (TDW *Redskin* foam pig, S.U.N.Engineering squeegee pig and F.H.Maloney sphere), none of them could be stalled in the fitting. This characteristic was found to result from the wye fitting ID being slightly smaller than the transit spool in the area just before the crotch opening. When the pigs were slowly pigged into the wye fitting, they would stop at the restriction until the pressure was increased sufficiently to force them past the restriction. As soon as the pig passed the restriction, the stored energy in the transit spool was sufficient to push the pig through the wye fitting and into the outlet. This characteristic is of extreme importance, and suggests that wye fittings can be made more "pig-friendly" by relieving the ID just in front of the crotch area.

Several pigging tests were also performed on a Select Industries soluble sphere. However, since there is essentially no differential pigging pressure required, the conventional data reduction techniques could not be used. In the two tests performed, the soluble sphere passed through the wye fitting at flow rates of approximately 75gpm and 100gpm, respectively, with no problem. In fact, during these tests, the soluble sphere actually flowed uphill and through the fitting without falling down to the opposite side, which had no flow and was at a lower elevation than the outlet.

There were also five tests performed with a misaligning flange installed in the transit spool. The VetcoLog intelligent pig was tested once with a 5° offset in the misaligning flange, and twice with a 10° offset. The TDW dual-diameter (14 x 10) scraper pig and the Knapp Polly Pig dual-diameter (14 x 10) gauging pig were also tested once each, with a 10° offset.

CONCLUSIONS

The test results showed that all of the pigs tested can pass through the symmetric wye fitting geometry without problem and without damage to the pig or the fitting. Moreover, the successful passing of each type of pig was demonstrated under a wide range of flowing conditions, i.e. pig velocities and flow conditions in the opposite inlet.

The tests using air with the short, light pigs, such as the foam pigs and spheres, show that concerns over stalling pigs with high by-pass potential can be eliminated by simply undercutting the inside of the fitting. For these types of pigs, it is recommended that the ID of the fitting be enlarged to remove at least one-half of the pig squeeze just prior to the crotch area. This generally amounts to approximately a 2-4% increase in the wye fitting ID in the undercut region.

The test results presented in this paper are exclusively for 10-in pigs and for dual-diameter (14 x 10) pigs passing through a 10in x 10in x 10in piggable wye. Additional testing is required over a range of other sizes before the results can be generalized for all sizes.

There are a large number of pigs used routinely in pipeline construction and production operations that have not been tested. Therefore, additional tests are recommended to extend the conclusions to other pigs. Specifically of interest are the other large, heavy, intelligent pigs, such as the British Gas On Line Inspection pig and the Tuboscope *Intalog* pig.

ACKNOWLEDGEMENTS

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kind permission to publish the pig testing results.

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Pipeline Pigging Technology

PIG DESCRIPTION	PEAK PIGGING DIFF PRESS IN TRANSIT SPOOL(PSI)	PEAK PIGGING DIFF PRESS IN "Y" SPOOL(PSI)	TRANSIT SPOOL AVERAGE VELOCITY
Select Industries Soluble Sphere	0	0	.30-.40 FPS ¹
TDW Redskin Foam Pig	5-9	2-10	.59-20.0 FPS
F. H. Maloney Sphere	6-10	N/A	4.5-20.0 FPS
Knapp Foam Pig	11-25	6-25	.74-5.20 FPS
Knapp Dual-Diameter (14X10) Gauging Pig	10-33	11-37	.91-5.18 FPS
TDW Dual-Diameter (14X10) Scraper PIG	20-51	7-42	.41-6.90 FPS
TDW Redskin Foam PIG & Dual-Diameter(14X10) Scraper Pig(Pig Train)	22-38	25-38	.88-2.16 FPS
Knapp Foam Pig & TDW Dual-Diameter(14X10) Scraper Pig(Pig Train)	29-40	27-50	.81-1.64 FPS
Sun Engineering Squeegee (Cup-Type) Pig	37-42	N/A	5.00-16.7 FPS
VetcoLog Intelligent Pig	54-89	17-64	1.04-4.78 FPS

1. Soluble sphere velocities based on flow rates.

Table 1. Summary of pigging results.

Pigging through Y fittings

(USING WATER)			
PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
9	.59 FPS (146 GPM)	10	400-550 GPM
9	.92 FPS (214 GPM)	6	NO FLOW
6	2.23 FPS (519 GPM)	2	300-450 GPM
5	2.31 FPS (567 GPM)	4	NO FLOW
9	2.50 FPS (582 GPM)	4	100-200 GPM
7	2.60 FPS (606 GPM)	7	NO FLOW

Table 2. TDW 'Redskin' foam pig (using water).

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PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
23	.74 FPS (173 GPM)	23	NO FLOW
18	.87 FPS (202 GPM)	9	100-200 GPM
11	1.22 FPS (303 GPM)	16	NO FLOW
18	1.48 FPS (364 GPM)	12	400-550 GPM
25	1.88 FPS (464 GPM)	25	NO FLOW
25	5.20 FPS (1,212 GPM)	6	NO FLOW

Table 3. Knapp Polly Pig foam pig (using water).

Pigging through Y fittings

PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
26	.41 FPS (102 GPM)	28	NO FLOW
28	.63 FPS (145 GPM)	27	100-200 GPM
20	.66 FPS (163 GPM)	33	400-550 GPM
32	.74 FPS (173 GPM)	22	NO FLOW
28	1.35 FPS (333 GPM)	35	400-550 GPM
23	1.73 FPS (425 GPM)	28	NO FLOW
32	1.78 FPS (437 GPM)	42	NO FLOW
31	2.08 FPS (484 GPM)	8	NO FLOW
33	2.23 FPS (518 GPM)	27	100-200 GPM
30	2.40 FPS (559 GPM)	10	NO FLOW
51	3.68 FPS (855 GPM)	7	NO FLOW
25	6.90 FPS ¹ (1,698 GPM)	18	NO FLOW

1. Pig also passed through Misaligning Flange with 10 degree offset.

Table 4. TDW dual-diameter (14 x 10) scraper pig (using water).

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PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
38	.81 FPS (189 GPM)	27	NO FLOW
40	.91 FPS (211 GPM)	29	100-200 GPM
39	1.17 FPS (292 GPM)	43	300-450 GPM
29	1.25 FPS (306 GPM)	34	400-550 GPM
36	1.35 FPS (336 GPM)	37	300-450 GPM
39	1.35 FPS (336 GPM)	47	NO FLOW
37	1.48 FPS (368 GPM)	50	NO FLOW
35	1.64 FPS (403 GPM)	37	NO FLOW

Table 5. Knapp foam pig and TDW dual-diameter (14 x 10) scraper pig in a pig train (using water).

Pigging through Y fittings

PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
22	.84 FPS (197 GPM)	37	400-550 GPM
34	.88 FPS (204 GPM)	25	NO FLOW
25	1.60 FPS (392 GPM)	33	NO FLOW
38	2.16 FPS (502 GPM)	28	100-200 GPM

Table 6. TDW 'Redskin' foam pig and dual-diameter (14 x 10) scraper pig in a pig train (using water).

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PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
26	.82 FPS (191 GPM)	17	NO FLOW
10	.91 FPS (211 GPM)	33	400-550 GPM
33	1.49 FPS (346 GPM)	37	300-450 GPM
12	1.78 FPS (437 GPM)	24	NO FLOW
31	2.08 FPS (485 GPM)	12	NO FLOW
30	2.40 FPS (559 GPM)	29	100-200 GPM
19	5.18 FPS ¹ (1,274 GPM)	11	NO FLOW

1. Pig also passed through Misaligning Flange with 10 degree offset.

Table 7. Knapp dual-diameter (14 x 10) gauging pig (using water).

Pigging through Y fittings

PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
83	1.04 FPS (255 GPM)	59	NO FLOW
85	1.64 FPS (402 GPM)	48	NO FLOW
54	2.59 FPS ² (636 GPM)	17	NO FLOW
81	2.70 FPS (665 GPM)	64	300-450 GPM
89	3.11 FPS (764 GPM)	42	300-450 GPM
59	4.78 FPS ² (1,176 GPM)	23	NO FLOW
65	4.78 FPS ¹ (1,176 GPM)	61	NO FLOW

1. Pig also passed through Misaligning Flange with 5 degree offset.

2. Pig also passed through Misaligning Flange with 10 degree offset.

Table 8. Vetcolog intelligent pig (using water).

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PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(Psi)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (Psi)	FLOW IN OPPOSITE SIDE
5	4.1 FPS (175 SCFM)	N/A	687 SCFM
5	5.6 FPS (259 SCFM)	N/A	NO FLOW
6	10.0 FPS (510 SCFM)	N/A	NO FLOW
6	20.0 FPS (1,477 SCFM)	N/A	NO FLOW

Table 9. TDW 'Redskin' foam pig (using air).

PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(Psi)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (Psi)	FLOW IN OPPOSITE SIDE
37	5.0 FPS (769 SCFM)	N/A	NO FLOW
42	7.7 FPS (355 SCFM)	N/A	2,107 SCFM
39	8.3 FPS (1,108 SCFM)	N/A	NO FLOW
38	16.7 FPS (1,293 SCFM)	N/A	NO FLOW

Table 10. S.U.N.Engineering 'squeegee' cup-type pig (using air).

Pigging through Y fittings

PEAK PIGGING DIFF PRES IN TRANSIT SPOOL(PSI)	TRANSIT SPOOL AVG VEL (FLOW RATE)	PEAK PIGGING DIFF PRES IN "Y" (PSI)	FLOW IN OPPOSITE SIDE
6	4.50 FPS (184 SCFM)	N/A	1,293 SCFM
5	6.30 FPS (769 SCFM)	N/A	NO FLOW
10	10.0 FPS (1,539 SCFM)	N/A	NO FLOW
10	20.0 FPS (1,643 SCFM)	N/A	NO FLOW

Table 11. F.H.Maloney inflatable sphere (using air).

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PART 4

THE CONSEQUENCES OF INSPECTION

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INTERPRETATION OF INTELLIGENT-PIG SURVEY RESULTS

INTRODUCTION

Recent years have seen a dramatic growth in the use of on-line inspection technology for the revalidation of operational pipelines. Much of this growth can be attributed to the success of high-resolution inspection technology in providing cost-effective solutions to a range of pipeline problems; the extensive application of these advanced services has allowed pipeline operators to confirm their accuracy and value.

As with all pigging operations, the technical details associated with the in-field running of inspection tools is of great importance to both the inspection contractor and the pipeline engineer, and adequate preparations in advance of any in-field work are essential if expensive errors or delays are to be avoided. Ultimately, however, the provision of inspection data in a final report is the sole objective of running an on-line inspection tool in a pipeline, and the value of the entire exercise is determined only by the quality and nature of the information contained in the report.

This paper addresses a number of important aspects relating to British Gas' inspection technology and to the eventual interpretation of data and preparation of inspection reports.

ACQUISITION OF PIPELINE DATA

In most circumstances, pipelines are selected for on-line inspection on the basis of some form of risk assessment. This is usually related to considerations for personnel safety and security of supply for gas pipelines, and with an additional consideration for pollution in the case of liquid lines. Although such assessments are often of a qualitative nature, an increasing number of pipeline

operators are adopting formalized, quantitative schemes, which can be used to great effect in ensuring that the most appropriate inspection, repair and maintenance programmes are employed over the life of a pipeline.

Once the decision has been made to perform an on-line inspection survey of a pipeline, considerations of technical standard and cost become the focus of attention. The two factors are closely related, since the inspection phase of a project cannot be financially divorced from the consequent costs of remedial work and the subsequent costs of pipeline maintenance. The inspection service must, therefore, be regarded as an integral part of pipeline maintenance, with the accuracy and repeatability of the service determining the final out-turn of maintenance costs.

Preparation

Before a pipeline is inspected, it is prudent to perform a detailed review of its engineering records to gain early information about its suitability for on-line inspection. This phase is usually complemented by extensive discussions with the pipeline operator, and an on-site survey of the line by a British Gas engineer. Once it has been established that the pipeline is suitable for the running of an inspection tool, the in-field operational phase can begin.

In-field tool running

This phase comprises a series of operations, carried out in a specific order to ensure the successful running of the inspection tool. The first part entails the running of cleaning and bore-proving pigs, to provide optimum conditions for inspection; the second part involves the running of the inspection tool itself.

Extensive preparatory work ensures the timely execution of this part of the service, together with specialized handling equipment to simplify the insertion and extraction of pigs. In addition, the detail of inspection tool design provides a virtual guarantee that the tool will pass through the pipeline without becoming stuck or damaged.

Validation of survey data

Of particular importance in the field is the post-inspection validation of the survey data, and this occurs following the withdrawal of the magnetic tape store from the on-board tape recorder. During the inspection operation, data

will have been processed digitally in real time, securely coded against errors, and organized in a particular format for acceptance by the on-board tape recorder. Clearly, early validation of the data, to confirm the successful operation of the system, is essential. This is a complex task in view of the huge quantities of data involved, and has demanded major developments in microcomputer-based test equipment for its completion. Following the confirmation of a successful survey run, the magnetic tape, containing the inspection data, is returned to the British Gas Computer Centre in England for detailed analysis and interpretation.

Interpretation of inspection data

At the On-Line Inspection Centre, the data recorded on tape during the inspection run is replayed via a process-control type of computer on to standard computer tapes, which can then be analysed using one of the Centre's five main computers. These machines reformat and reorganize the data so that information from the various types of sensor is properly aligned and correlated with positional data.

The next process is to reject signals from normal, defect-free pipeline fittings such as welds and bends. Each fitting gives a particular shape of signal which can be identified, checked and then eliminated. If existing pipeline maps resulting from previous inspection runs are available, these are also used to verify and reject data. Significant sensor data is then presented on an electrostatic plotter, and interpreted by trained operators. This form of output allows many parallel sensor traces to be plotted and quickly analysed.

Finally, a mathematical sizing model, used in conjunction with a computer graphics terminal, is employed to obtain a direct estimate of the size and shape of defects. This system is complemented by a comparative sizing technique based on an automatic search through a large library of known signals.

Inspection data must be preserved for comparison with subsequent inspection logs and as a historical record. The scale and frequency of inspection operations demand that data analysis must be a highly-automated process. The keys to rapid and reliable data analysis are defect sizing capability, and the ability to recognize and classify automatically the signals which characterize particular pipeline fittings. When such a signal is identified, it is necessary to check that the fitting is not faulty in some way, for example to check that a weld between sections of pipe has not become corroded. The integrity of each fitting must be verified, but the obvious approach of comparing new signals with standard examples works only in a limited number of cases.

For instance, a good weld at one point in a pipeline can produce a very different image from an equally-good weld at a different point on the same pipeline. More sophisticated techniques have had to be used.

Possible faults are analysed using pattern-recognition and image-processing techniques similar to those employed in medical scanning and satellite imaging. Such techniques, originally developed for purposes like enhancing blurred photographs, or teaching computers to recognize particular words, are equally relevant to the interpretation of pipeline inspection data. Instead of a blurred photograph, the on-line inspection device provides a record of magnetic field variations in the pipeline; its sharpness is limited by the response of sensors and electronics and the errors introduced during data collection in the harsh conditions inside a pipeline.

British Gas has modified and developed existing techniques to cope with the problems posed by pipeline inspection. The general approach has been to measure various parameters to characterize a signal and then to use statistical techniques to discriminate between significant and spurious data. Much depends on choosing the appropriate image parameters to measure. The experience of engineers who design and operate inspection vehicles has proved invaluable for this purpose.

The data-reduction techniques employed are designed to operate in a cascade fashion, so that only the simplest operations are applied to the bulk of the inspection data, more complex steps being reserved for later stages in the analysis sequence. Using various software tools, the operator may search for particular types of feature, manipulate images on graphics terminals, and test new signal-processing algorithms to identify any misclassification errors. These techniques have been developed at the On-Line Inspection Centre and by leading consultancy organizations working under contract.

The procedure may be modified when dealing with data from seamless pipe in which the method of manufacture produces large variations in wall thickness (often outside specified tolerance limits) over quite small areas of pipe. In addition, the amount of metal-working associated with the forging process also produces significant variations in the material's magnetic characteristics. Such wall-thickness and magnetic variations are detected by magnetic-flux leakage inspection vehicles, and can obscure or distort signals from potential defects. A special de-blurring process has been developed by British Gas which enables the "natural" variation in response to be recognized and eliminated without distorting the signals from metal-loss defects. The end product is corrected data which looks like that obtained from pipes manufactured from controlled-rolled plate.

Interpretation of pig survey results

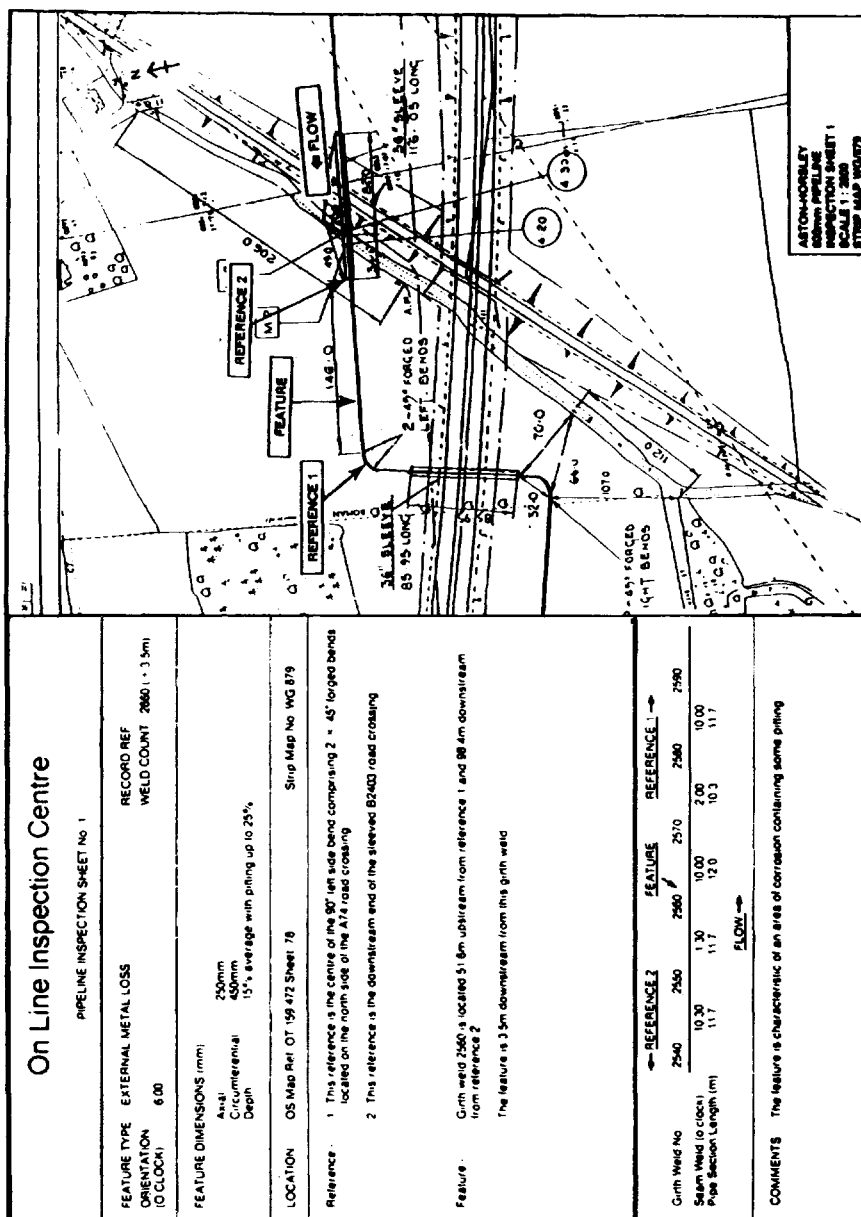


Fig.1. Feature report giving feature size and location.

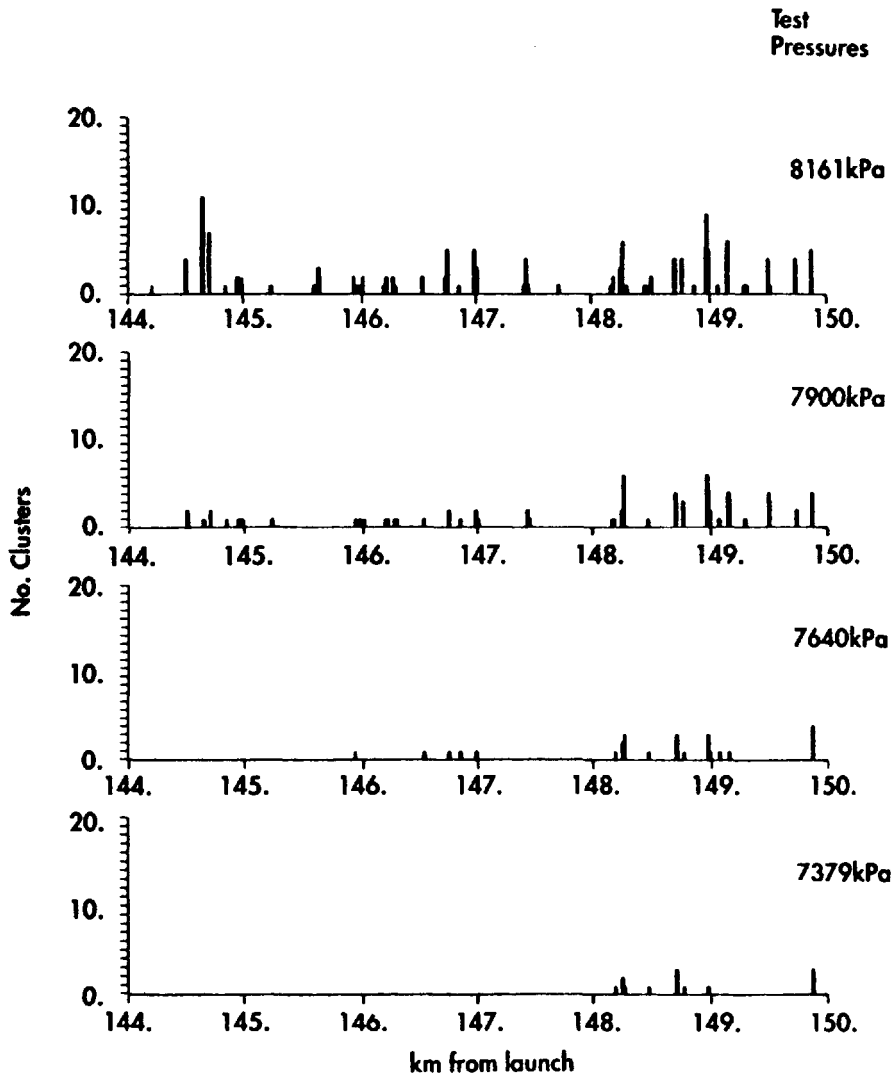


Fig.2. Frequency distribution of metal-loss features.

Interpretation of pig survey results

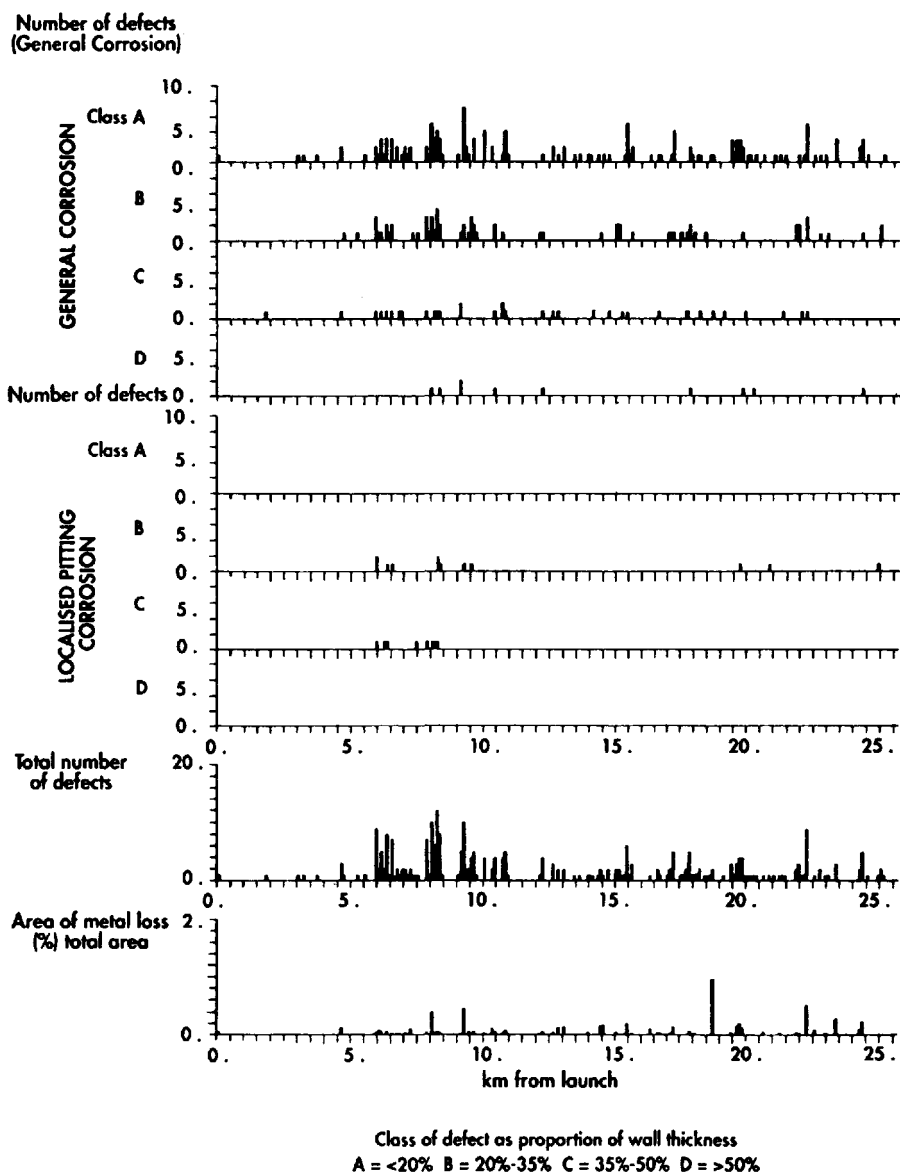


Fig.3. Frequency distribution for various depths of corrosion.

Reporting

The analysis and interpretation procedures result in a computer file containing detailed information about pipeline flaws and their geographical positions in the pipeline. The final step in the process is then to prepare a report which will provide the pipeline operator with the necessary information to take remedial action where required. This report can be formatted in a wide variety of forms, and must be structured to reflect the overall condition of the pipeline. In the case of pipelines containing relatively-small numbers of reportable features, each flaw can be individually described in a written report, giving the size and location of the feature. An example of this type of report is shown in Fig.1.

However, where the number of reportable features is large, it becomes necessary to process the survey data statistically to give the pipeline operator an initial overview of the pipeline's condition.

The format of the report which provides this initial overview can be tailored to suit the needs of individual pipeline operators, but experience has shown that certain formats are of particular benefit. One example of such a report is shown in Fig.2, where the number of metal-loss features which would fail at selected test pressures is shown against distance along the pipeline. Another example is shown in Fig.3, where the metal loss is described in terms of its depth and area, and is differentiated into pitting and general corrosion.

In preparing reports for the pipeline operator, the principal concern is to ensure that the data type, and its presentation, are selected to satisfy the needs of the pipeline engineers who are to perform remedial work. To this end, British Gas has evolved a highly-flexible reporting structure which undergoes constant review. Ultimately, however, it is the quality of information which determines the overall value of the inspection service.

RISK ASSESSMENT AND INSPECTION FOR STRUCTURAL INTEGRITY MANAGEMENT

GAS-TRANSMISSION companies are under increasing pressure from several directions to develop and manage pipeline integrity programmes in a responsible and cost-effective manner. The issues of pipeline reliability and safety of an ageing North American pipeline system are receiving increased public and regulatory attention. Record gas volumes on NOVA and other pipeline systems result in operations close to the design capacity for much of the year, increasing the business emphasis on reliability.

NOVA's operating experience over a period of 32 years has led to the development and implementation of a comprehensive pipeline integrity programme that provides a cost-effective contribution to the reliable operation of the gas-transmission system. This paper describes the methods used to identify specific pipeline segments for integrity assessment, and the role of in-line inspection with instrumented pigs, and other monitoring methods, to ensure safety and reliability of operation by maintaining the structural integrity of the pipeline system.

INTRODUCTION

The Alberta Gas Transmission system of NOVA, illustrated in Fig.1, has been developed over a period of 32 years. It transports 13% of the gas produced annually in Canada and the United States, and virtually all of the gas exported from the Province of Alberta. The system includes 40 compressor station sites, and approximately 15,600km (9,700miles) of buried pipeline, mostly operating in Class 1 locations. The pipelines consist of approximately

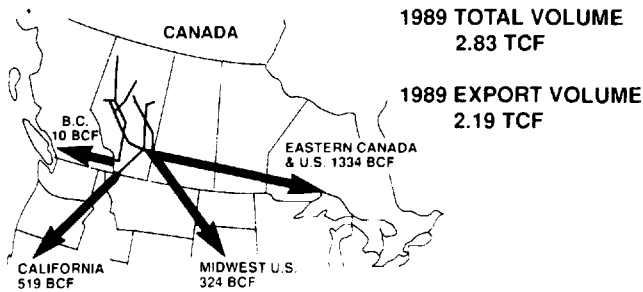


Fig.1. Nova's Alberta gas transmission division.

800 segments, each with its unique characteristics of size, terrain, materials, construction practice, operating history, and current gas flow.

The need for a comprehensive pipeline integrity programme to maintain the structural integrity of our system arises from recognition of several factors which are not unique to just our system:

1. Our own experience, like that of other companies, shows that deterioration of structural integrity does occur in some pipeline segments of our complex system due to mechanisms such as external corrosion, slope instability and stress corrosion cracking.
2. We have a clear responsibility to our regulators, our customers and our shareholders to prevent structural integrity problems from adversely affecting public safety, the reliable and economic transportation of gas, and the value of our assets.
3. Operating close to design capacity on a year-round basis, as Fig.2 shows we have been recently, requires that pipeline integrity projects be scheduled with lead times of one to two years to minimize disruption to operations. We need to do more to anticipate and prevent problems rather than simply react to them.
4. There are continuing signs, from newspaper coverage[1], US Public Law 100-561 [2], and NEB of Canada recommendations[3], for example, that regulators may impose uneconomic requirements for periodic inspection or testing unless operators demonstrate that they are now meeting their responsibilities for maintenance of an ageing buried pipeline system.

Most important in the discussion of pipeline integrity is our belief that we, as owners and operators, know more about the structural integrity of our

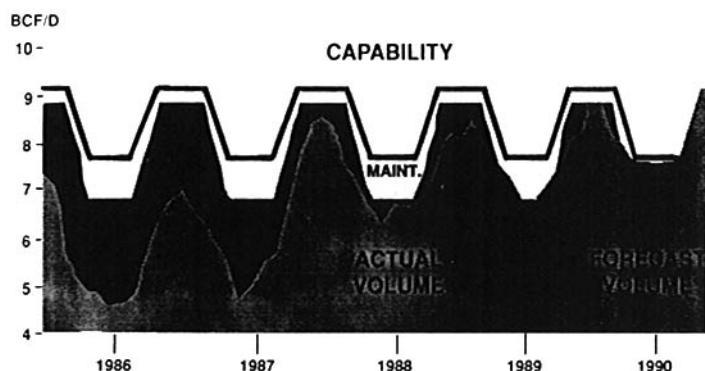


Fig.2. Trend to increased load factor.

system, and what is required to maintain it, than any other organization. In the past we have been thorough about documenting failures, determining their causes, and implementing measures to improve our design, construction and operating procedures. We have learned from this activity, over a period of 32 years, what deterioration mechanisms reduce the structural integrity and where they are likely to cause future problems. The experiences of other pipeline operators, and our active participation in research and development, have also provided information relevant to understanding the structural integrity of our system. Although we believe we know more about this subject for our system than anyone else, and have developed a sound approach to pipeline integrity planning and maintenance, we also recognize aspects of our programme that can be improved, and will continue to refine the approach.

GOAL OF PIPELINE INTEGRITY PROGRAMME

The primary goal of the programme is to prevent structural integrity problems from having a significant effect on public safety or business operations by identifying and performing those inspection, monitoring and repair activities that can be most effective. The secondary goal is to communicate the programme within our company, and to other interested parties, to improve the programme, and to establish knowledgeable support for it.

Alternative approaches

We recognize that a number of options are available for rehabilitation and repair methods that may even include replacement of long sections of pipeline. The rehabilitation projects performed by the industry in recent years illustrate the range of methods that have been used to assess the risks and structural integrity and to perform repairs to return a damaged pipeline to the condition that meets applicable design standards[4,5].

Many operators[6] report the combination of hydrotesting, repair by cut-out, and recoating to be a practical approach for rehabilitation of pipeline segments 5 to 30km in length. However, some concerns related to the effectiveness of this approach have also been raised. A recent experience[7] suggests that in some cases pipelines could have been replaced at a lower cost than the cost of the rehabilitation involving cut-out repairs and recoating. This kind of indication amplifies a need for an accurate and reliable assessment of structural integrity of pipelines prior to making rehabilitation and repair decisions.

Our own experience with two major pipelines containing many corrosion indications has confirmed the usefulness of an approach that relies on sound information about the condition of a line. Engineering critical assessment (ECA) of corrosion damage accurately sized by an advanced ILI tool proved to be the most cost-effective rehabilitation method. Less than ten reinforcing sleeves, and no cut-out or recoating, were required in 1985 to re-establish the structural integrity of about 800km of pipelines[8]. Both pipelines have provided failure-free service since that time. The rehabilitation method involving periodic inspection, ECA and repair continues to be more than one order of magnitude more cost-effective than other rehabilitation alternatives.

The following sections of this paper outline the methods developed to assess the risks and to direct inspection to pipelines where increased risk of deterioration of structural integrity is indicated. A summary of the results obtained in implementing the approach during the last three years is provided as well.

RISK ASSESSMENT AND PIPELINE INTEGRITY

Methods that assess the risks related to structural integrity problems have been described by authors representing British Gas plc[9,10], Tenneco Gas Transportation Co[11], and TransCanada Pipelines Ltd[12]. Each of these

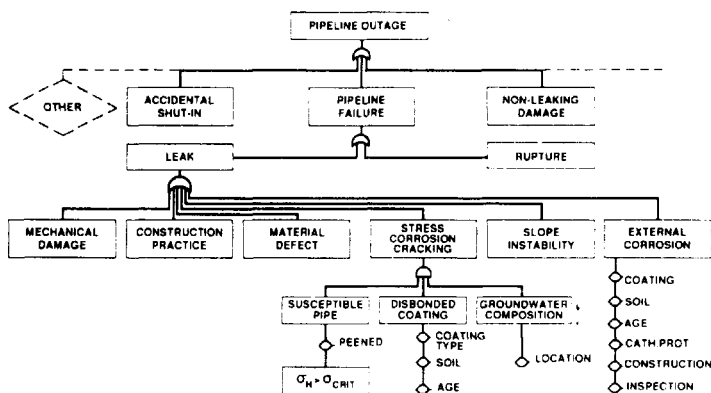


Fig.3. Partial fault tree for outage probability.

methods uses a formula that includes various factors related to expected pipeline condition and consequences of failures. The calculated index or ranking of pipeline sections indicates the priority for inspection. The formula used by each company reflects aspects of the materials, system configuration and business situation that are specific to its pipeline system.

We recognized that none of the formulae used by other companies could be directly applied to our system, and we have adopted fault-tree analysis as a tool for risk assessment. It provides a logical structure that helps us to understand the component of outage probability and risk, to perform the analysis required to quantify them, and to communicate the results. The analysis method also is useful to describe the reduction of risk accomplished by pipeline integrity projects that reduce outage probability.

Outage probability

The probability of an outage caused by a structural failure, which is one of the key factors required to assess safety and economic risks, is estimated using the fault tree illustrated in Fig.3. The data to estimate outage probabilities are derived largely from our own engineering studies, data on pipeline characteristics and failure statistics, supplemented by industry data and experience.

The details of the analysis are beyond the scope of this paper; however, it is important to understand that for each pipeline segment the method allows the contribution, to the total outage probability, of each significant failure cause to be estimated separately. This helps to recognize how pipeline

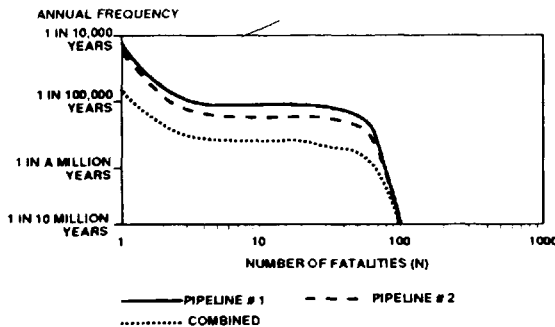


Fig.4. Risk spectra for a specific location (accidents with N or more fatalities).

integrity projects intended to reduce or eliminate corrosion failures, for example, will reduce the total outage probability, but will not totally eliminate failures which may still occur due to other causes.

The fault-tree branch for stress corrosion cracking (SCC) was only recently included, and is expected to evolve as industry understanding and experience develops. Although SCC has been located in the system and led to one hydrostatic testing project, no operating failures have occurred.

Safety risk

The probability of life loss for a leak or rupture can be considered as:

$$(\text{Probability of life loss}) = (\text{probability of an ignited gas release}) \times (\text{probability of occupied lethal site})$$

The safety risks associated with deterioration of structural integrity really amount to the risk of being in the wrong place at the wrong time, when a failure occurs. With only a few exceptions, the NOVA system is remote from populated areas, and these risks are estimated to be very low for both employees and the public. This is consistent with the excellent safety record of the NOVA system and other gas pipelines. No life-loss or injury incident has been recorded from a leak or rupture over the life of the NOVA system. To the present time, only one pipeline integrity project has been initiated specifically to reduce public safety risk because the risks are assessed as being very low.

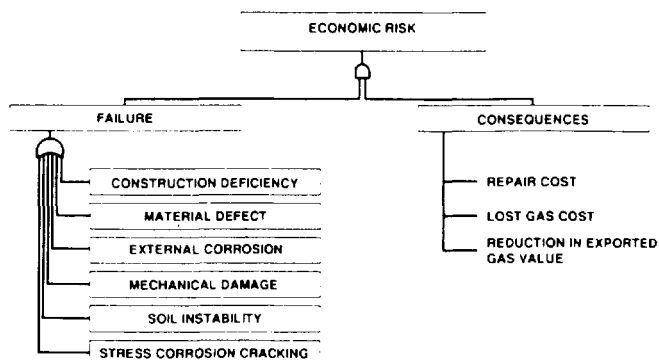


Fig.5. Schematic of economic risk assessment.

While the estimates of the outage probabilities required for the life-loss analysis are considered to have acceptable accuracy, more work is needed to improve our confidence in methods used to estimate the probabilities of associated consequences resulting from outage involving fire. The approach that shows some promise in this regard focuses on developing risk spectra for specific locations in which a pipeline facility passes close to a centre of population.

Fig.4 illustrates the results that would be obtained for a specific site where the probability of an event causing N or more fatalities is a function of the number of fatalities N . This particular form of presentation appears to be useful, in that it considers the full range of potential consequences. While it is recognized that the concept of risk spectra has been used in other industries[13,14], as well as in the gas-transmission industry[15] in Europe, some fundamental questions will have to be addressed before this concept finds a broader acceptance. Namely, what is the acceptable level of risk, what assumptions should go into the estimates, since the results are sensitive to the input, and how do we evaluate the benefits of remedial action. We need to be able to decide, for example, whether it is worth spending \$10million to reduce outage probability by a factor of 2.

Economic risk

Economic risks have had a strong influence on our pipeline integrity programme because the safety risks are estimated to be very low, and are consistent with the excellent safety record. The fault tree used to estimate economic risk is illustrated schematically in Fig.5, which shows that:

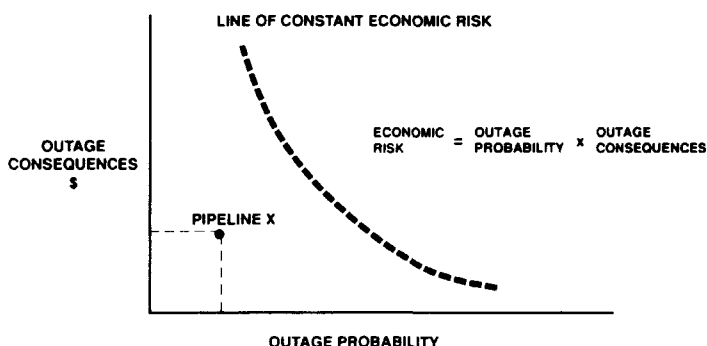


Fig.6. Economic risk components.

Economic risk = outage probability x outage consequences

One of the most significant components included in the estimate of outage consequences is the potential reduction in exported gas volumes, caused by an outage. Although this is not a direct cost to NOVA and its estimated value is subject to some assumptions, it is included to recognize the importance of each pipeline segment to the reliable performance of the Alberta gas industry. The other components of outage consequences are the value of lost gas and repair cost.

The results of the economic risk assessment can be effectively illustrated using the diagram in Fig.6, which shows how the probability and consequences are contributing to the economic risk. In general, pipeline segments with high outage probability are those with a history of known specific problems, (Points 1, 2 and 5, for example, in Fig.9) which require monitoring and maintenance on a periodic basis to prevent operating failures. Inspection and assessment projects for such lines have historically been the core of our pipeline integrity programme; however, in recent years, projects have been planned and carried out on other pipeline segments based solely on the results of the economic risk assessment. These lines generally have only moderate outage probabilities, no history of failures, but high outage consequences (Points 3 and 4 in Fig.7, for example).

The effect of a pipeline integrity project is to reduce the outage probability for a pipeline segment, shifting its position to the left, as shown for several completed projects in Fig.8, to a lower value of economic risk.

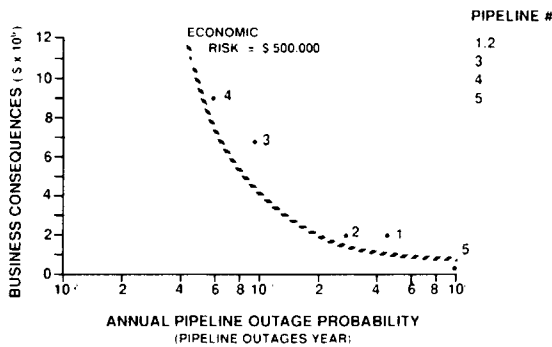


Fig.7. Economic risk for selected pipeline segments.

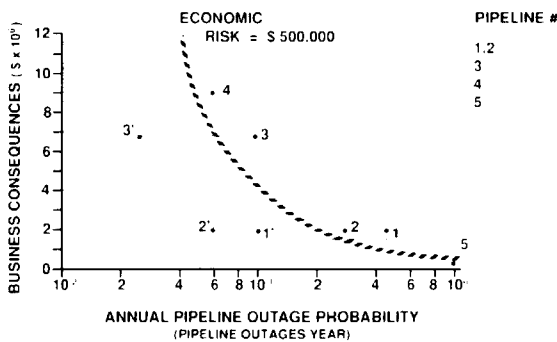


Fig.8. Reduced economic risk for completed pipeline projects.

IDENTIFYING PIPELINE INTEGRITY PROJECTS

The economic risk assessment essentially provides a ranking of pipeline segments according to the potential effect of a failure on our business: the first step in reaching our primary goal. The next step is to develop pipeline integrity projects that will reduce the economic risk by lowering the probability of failures caused by deterioration of structural integrity. Some of the guidelines for approval of projects in the programme are:

1. Projects to prevent outages on pipelines with a known integrity problem that would otherwise cause recurring failures must be included in the programme.
2. Priority for action is indicated by first addressing unacceptable safety risks and then by the ranking of economic risk.
3. Cost of an individual project $\leq 50\%$ of the estimated outage consequences.
4. Annual programme cost should be approximately 1-2% of operating and maintenance costs.

Fig.9 provides a summary of the projects either completed in, or planned for, the years 1988 to 1990 inclusive. It is noteworthy that 55% of the programme expenditures have been on projects to assess the condition of pipelines anticipated to have developing structural integrity problems but with no history of failures or observed damage. 72% of the total expenditure was aimed at reducing the risks associated with external corrosion.

External corrosion projects

At the present time, external corrosion is the largest component (approximately 80%) of the estimated outage probability for pipelines with the highest estimated economic risk. The two pipelines with known external corrosion (Table 2) were, or will be, re-inspected using an "advanced" in-line inspection (ILI) system. The approach of using in-line inspection and analysis in preference to hydrostatic testing, as described in an earlier paper[5], has proven satisfactory and is continuing.

The three pipelines with anticipated problems were identified solely on the basis of the estimated risk. "Conventional" ILI systems were used on two of the lines and an "advance" ILI system was used on the other line. External corrosion of varying severity and extent was found on each of these pipelines

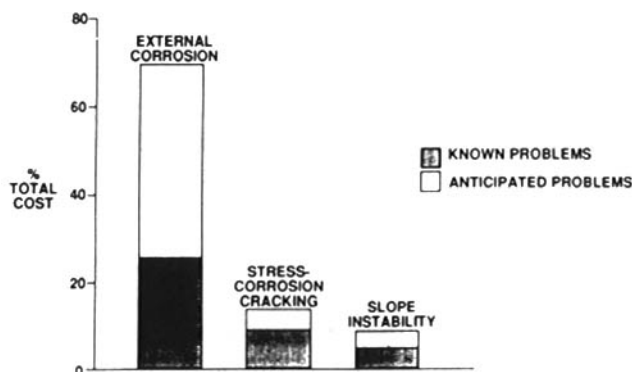


Fig.9. Distribution of programme costs (1988-1990 incl).

in qualitative agreement with the predictions of the fault-tree analysis. By completing the ILI projects, it is considered that the probability of an outage caused by corrosion has been essentially eliminated for those pipelines, so that the position of these pipelines on the economic risk diagram is reduced, as shown by points 1, 2 and 3 in Fig.8. In the three-year period from 1988 to 1990, we will have inspected a total length of about 1200km with the highest estimated economic risk of corrosion failures. This is approximately 20% of the total length of large-diameter (>16") pipelines in our system.

Stress corrosion cracking (SCC) projects

Most of the projects related to SCC have been aimed at gathering data to more accurately assess the probability of SCC occurring. Expenditure on these projects account for 16% of total programme costs in the years 1988 to 1990. Projects to excavate specific locations on six pipelines estimated to have a high risk of SCC occurring were initiated in 1987. One of the pipelines was found to have SCC, which initiated further projects in 1988 to assess more locations on that line, which in turn led to a hydrostatic test in 1989. A 1990 project is planned to excavate and examine specific locations on one other

pipeline where SCC was discovered in the vicinity of a removed dent, and to excavate selected locations on several other pipelines.

Slope instability projects

Total expenditures related to pipelines with slope stability problems amount to 12% of programme costs, with nearly half of those costs attributed to one location where river bank movement has caused a previous failure. For the past three years, pipe movement at that location has been monitored using a satellite global positioning system installed on the pipeline [16], which indicates that reconstruction will be required within the next year to protect the pipeline from continuing soil loading. Monitoring of slope movement is expected to continue at another nine river crossings where slope movement is occurring. Costs for these other slope monitoring projects are comparatively low, at less than \$25,000 per year for each site.

COSTS AND BENEFITS

Costs

The total cost of the programme will be approximately 2% of the operations and maintenance costs for the pipeline system for the years 1988 to 1990 inclusive. As mentioned earlier, just over half the expenditures have been on assessing lines with anticipated integrity problems, with the rest spent on monitoring lines with known integrity problems and a risk of recurring failures.

Benefits

The need to periodically assess the condition of lines recognized to have a risk of recurring failures is almost self-evident. Failure to do so would likely result in regulatory action as a minimum, and would not be consistent with NOVA's commitment to operate a safe and reliable system. The benefits of an established programme for monitoring the integrity of such lines includes:

Risk assessment and inspection for integrity

1. Demonstrating to operating personnel, the public, regulatory authorities and our customers the commitment to operate a safe and reliable pipeline system capable of operating at its design capacity.
2. Maintaining the value of gas transmission assets.
3. Allowing scheduling of maintenance operations to minimize disruption and avoid unplanned outages for repairs.

The benefits of extending NOVA's pipeline integrity programme to include lines with no history of failure are perhaps more intangible and less obvious, since the long-term gain we expect to achieve involves some short-term pain. The projects do contribute to our operating costs, and may inconvenience the operations of our customers, yet it is not obvious in advance that failures would otherwise occur.

One of the intangible benefits of this part of the programme is the improved knowledge about the structural integrity of the buried pipeline system, and the reduced potential for future large, nasty surprises. Even though some projects have shown that failures due to deterioration of structural integrity are unlikely in the near term, the confidence in the reliability of critical parts of our system provided by this information, and the ability to plan future integrity activities based on factual data, has real value. A second intangible benefit of the total programme, related to the benefit of demonstrating a commitment to safe reliable operation, is the ability of NOVA, and other companies that have taken a leading role in managing pipeline integrity, to minimize outside interference in this aspect of our business.

The guidelines for selecting pipeline integrity projects are intended to introduce an element of cost-effectiveness that can be measured in the tangible benefits of preventing failures. If we are very successful in preventing outages in the medium term, the value of avoided consequences will be larger than the cost of the whole programme. It is too early to tell if this might be a realistic objective. On the basis of results for completed projects in the last two years, we can reasonably claim that the potential economic consequences of failures that otherwise would have occurred in the next five years represents 70% of the programme cost in those two years. The key to improving this result is to improve our accuracy in predicting the severity of deterioration, rather than simply the presence of deterioration.

At the present time then, we cannot claim that the whole programme can be justified in terms of tangible dollar benefits, but we believe that the intangible benefits are sufficient to continue the present approach.

DISCUSSION

The risk-assessment methodology that is the basis for our pipeline integrity programme has resulted in continued focus of our efforts to reduce the risks of failures caused by external corrosion. The resulting pipeline-integrity projects involve in-line inspection of pipelines which have very high economic consequences of an outage, or very large numbers of known corrosion damage areas. Both these situations place a premium on the ability of in-line inspection to provide data that allows failure pressures to be estimated without excavations to determine the size of corrosion damage.

When excavating locations to investigate external corrosion or stress corrosion cracking, it is NOVA's policy to reduce the pressure to 70% of the recent operating pressure to protect the safety of workers. Even with advance planning, such pressure reductions can affect border deliveries under the current situation with the system operating so close to capacity throughout the year. In the case of one project to assess anticipated corrosion on a line with moderate outage probability but very high outage consequences, such pressure reductions would have resulted in reduced gas exports valued at over \$1 million per day if any other operating disruptions occurred. As a result, an "advanced" ILI system, whose performance has been established[8], was used on this line, rather than a lower-cost conventional system, in order to avoid the excavations that would have been otherwise required to assess the significance of detected corrosion damage. Even so, the reduction in gas volumes required for in-line inspection is a disruption to system operation. We are examining methods of including such business effects in the cost estimates of pipeline integrity projects, to make sure that the cure (pipeline integrity project) is not worse than the disease (an unplanned outage due to a failure). We are also encouraging the vendors of inspection services to develop methods that will allow their equipment to perform in high-velocity gas streams, so that we can refer to it as "on-line" inspection, rather than "in-line", which it truly is at present.

CONCLUSIONS

1. NOVA's pipeline-integrity programme has allowed us to determine what testing and inspection programmes are appropriate to our system.
2. With a total cost of 2% of operation and maintenance costs, the programme is affordable.

3. The tangible benefits of prevented failures in the medium term are estimated to represent 70% of the programme cost in the last three years.

4. In addition to the benefits of prevented failures, the intangible benefits of confidence in critical parts of our pipeline system and a demonstrated proactive attitude to preventing failures are sufficient to consider the overall programme as cost effective.

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INTERNAL CLEANING AND COATING OF IN-PLACE PIPELINES

INTRODUCTION

As more and more emphasis is being placed on preventive maintenance, methods of suppressing internal corrosion in pipelines are receiving increasing amounts of attention. Internal corrosion may cause leaks, with possible disastrous environmental effects, or may cause the product carried by the line to become discoloured or otherwise contaminated. The costs associated with internal corrosion can be staggering, but can usually be prevented by one of several methods. This paper describes one such method, the "double-plug extrusion" process for applying coating to the inside of in-place pipelines. It will also address surface preparation for coating.

Three critical factors influence the success of any coating project: surface preparation, coating material, and application technique. The wrong choice in any area may cause premature failure or decrease the life of the coating. This, of course, is true of both internal and external coating, although these factors are more difficult to control and inspect internally. For this reason, methods must be used which offer the highest potential for success. A reputable, experienced service company is also a must.

The first step of any coating job is to thoroughly clean the inside of the pipe to properly prepare its surface. The preferred cleaning standard is a white-metal blasted finish (NACE #1 or SSPC SP5), which ensures optimal coating adhesion. The coating material, specifically selected to withstand the internal environment of the line, is then applied by extrusion between two compressible, spherical pigs.

SURFACE PREPARATION

The objective of surface preparation is to remove all deposits, including rust, scale, and salts that could interfere with the coating bond, from the line. It is highly desirable to create a deep, angular anchor pattern to which the coating will best adhere. After cleaning, the line should also be completely dry and blanketed by an inert gas to prevent flash rusting. All of these conditions can be achieved by *SANDJET*, the abrasive blasting procedure used in the InnerCure Pipeline Renewal Service developed by UCISCO (Union Carbide Industrial Services Co).

The *SANDJET* process involves scouring the inside of the pipeline with an abrasive material, such as flint, which is propelled in a high-velocity stream of nitrogen. The cleaning particles impinge upon the wall of the pipe at a low angle of incidence, gouging and/or chipping away at the deposit. All waste material is carried through the line with the nitrogen, and can be collected at the outlet. Because the pressure drops and the velocity increases as the nitrogen flows through the line, cleaning is more efficient in the outlet half of the line. Therefore, cleaning is typically performed in both directions to provide optimum surface preparation. After abrasive cleaning, pigs and/or solvents are used to remove any remaining dust. Erosion is minimized by tightly controlling the velocities of the nitrogen and cleaning material. The process can clean around any bends or elbows.

The equipment needed for the cleaning process consists of:

1. a mobile nitrogen pumping unit, usually a pumper truck (which vaporizes liquid nitrogen) or a tube trailer (which contains high-pressure gaseous nitrogen);
2. a trailer-mounted cleaning unit consisting of a feed pot and all equipment to accurately control the nitrogen flowrate and velocity and the feedrate of the cleaning material;
3. an injection device which is connected to the pipe's inlet by a standard flange;
4. a dust-suppression/waste-collection system, usually a vacuum truck or covered dumpster. All waste material is dry and easily disposed of by the customer.

Occasionally, *SANDJET* cleaning may uncover very thin, hard deposits, such as magnetite, which are more economically cleaned with chemicals. If this is the case, the line is abrasively cleaned again after chemically cleaning to re-establish the desired anchor pattern and remove chemical residue. Also,

by removing rust or scale, cleaning may expose leaks that must be repaired before coating.

Clear advantages of this system over traditional cleaning methods, such as pigging or chemical washing, are numerous. Most important is its ability to reach a NACE #1 or SSPC SP5 white-metal blasted finish, which eliminates any contamination that may prevent bonding between the pipe and coating. The cleaning particles produce a deep, angular anchor pattern that enhances the coating bond. The nitrogen used to propel the cleaning particles also dries the line and leaves it in an inert atmosphere to prevent flash corrosion. Most lines can be cleaned very quickly, in about eight hours. Also, long sections of pipelines can be cleaned per setup, reducing excavation costs and time. In general, the maximum length that can be cleaned per setup is a function of the inside diameter of the pipe. The ID (in inches) divided by three will give the length in miles that can be cleaned. For example, the method can clean up to four miles of 12-in pipeline per setup.

COATING MATERIALS

A wide variety of coatings have been used to internally coat in-place pipelines. The "double-pig extrusion process" requires specific physical properties, including that it be thixotropic, or lose viscosity under shear pressure. This enables the coating to be spread onto the pipe wall with pig pressure and then thicken immediately thereafter, to prevent the coating from running or sagging. Also, the coating must be at least 60% solids.

The most commonly-used coating is a two-part polyamide-cured epoxy. It is moderately chemical- and abrasion-resistant, and will withstand temperatures of up to 150°F under immersion service (220°F, atmospheric service) and pressures up to 500psig. The polyamide coating is recommended for lines carrying potable, fresh, and salt water, crude oils, transportation fuels, natural gas, and some solvents. It is not recommended for lines containing strong aromatics, strong organic acids, or high levels of sulphur dioxide or hydrogen sulphide. The minimum cure time for this coating is seven days at 70°F, although it may be force-cured much quicker if the line can be heated.

Many other coatings, such as polyamines and polyurethanes, have been used, depending on the operating conditions of the line. At this time, there is no clear choice of coatings for "hostile" environments (high-pressure and/or high-temperature). Much testing is currently being done in this area. Also of interest are coatings appropriate for service-water systems in nuclear power plants.

It is difficult to predict how long a coating material will last on the inside of a pipeline. UCISCO has been coating lines since 1977, and these coatings are still in place. The expected method of failure is flaking or chipping of the coating. The lines can then be recleaned (to remove the old coating) and recoated.

COATING APPLICATION

Coating is applied to in-place pipelines by placing the coating material between two pigs and propelling the pig train through the line. Several types of pigs, including multiple-cup-and-disc, bi-directional disc, and spherical, are commonly used. UCISCO prefers inflatable spheres because they are reversible, non-collapsible, can negotiate tight bends without leaving gaps, and will conform to internal pipe irregularities. Spherical pigs also produces thicker coating layers, usually 4-6mils (dry film thickness), as opposed to 1-3mils for other types of pig, which means that a line needs only one to two coats if done with spherical pigs.

The coating thickness is controlled by the size of the spheres (shear pressure on the coating) and the speed of the pig train. The speed is controlled by the differential pressure across the pig train, which is determined by the pressure differential upstream and downstream. Nitrogen is used as both the driving force and back pressure, because its flowrate and velocity can be easily controlled by the same pumping equipment used to clean the line, and because its inertness prevents any possibility of flashing of the solvent material (usually MEK) in the line. Typically, two coats are applied, one in each direction, to ensure thorough coating of welds, joints, and plugged laterals.

The "double-plug extrusion" process has several limitations. The coating serves as a barrier for future corrosion or product contamination, but it will not repair or cover leaks, or add structural strength to the line. All leaks must be repaired before coating, including those that can be uncovered during cleaning. While this method can clean and coat much longer lengths than most alternative methods, it cannot coat through diameter changes, and lines must be broken at these points.

CASE STUDIES

Many types of line have been successfully coated by the "double-plug extrusion" process. They include: potable water, raw water, brine, crude oil, refinery off gas, jet fuel, isopropyl alcohol, ethylene glycol, and others. Below are a few case studies.

Chemical solvent lines at shipping terminal

A large chemical producer coated 2000ft of new, buried 6-in carbon steel pipe to prevent iron and corrosion from contaminating several water-white chemicals. Their alternative, stainless steel pipe, would have cost up to ten times that of coating carbon steel.

Jet fuel lines at military base

Several military installations have coated jet fuel lines, both new and old, in order to prevent contamination from internal corrosion. Their alternative, cleaning and dewatering the fuel with filters and separators, was more costly and less reliable.

Water feed to steam generator used in crude oil production

An oil producer that uses steam for down-hole injection coated 5.5 miles of 10-in new water lines to the steam generators to prevent corrosion from contaminating the generators. Their alternative, pre-coated, or yard-coated, pipe was about 40% more expensive, and would leave coating gaps at the joints.

Boiler feed water line in refinery

A major refinery coated 1600ft of 4-in boiler feed water line which had severe flow restriction due to tuberculation. Their alternative, replacement of the pipe, was twice as expensive and would take much longer than coating.

Wet natural gas gathering lines

A major utility company coated 4.3 miles of 6-in and 4 miles of 4-in new natural gas gathering lines. The lines were being chemically treated with corrosion inhibitors, but the customer wanted additional protection in an environmentally-sensitive area.

Brine feedwater lines

A major producer of brine coated several sections of 12-in new, buried and floating line ranging from 5000ft to 10,500ft in length, in order to prevent corrosion in an environmentally-sensitive area. Their alternatives, slip-lining and yard-coating, were approximately three to four times the cost of coating the carbon steel pipe.

PART 5

THE FUTURE

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PIGGING RESEARCH

INTRODUCTION

Pipeline pigs may be broken down into two fundamental groups: *conventional pigs*, which perform a function such as cleaning or dewatering, and *intelligent pigs*, which provide information about the condition of a pipeline. Conventional pigs have been in use for over 100 years, compared to less than 25 years for intelligent pigs.

Few, if any, of the features incorporated in the design of conventional pigs are the result of fundamental research and development, while intelligent pigs owe almost everything to concerted R&D programmes.

Millions of dollars have been spent on intelligent pigs because there was (and is) a clearly-defined need. Conventional pigs have simply evolved.

The reason that they have evolved, rather than being the result of development programmes, is that specific performance requirements have never been set.

A pig is considered "Good" if it travels through a pipeline without problems, preferably arriving in pristine condition. What it has done during the run is never precisely known. Whether its performance could have been improved is generally not apparent until a different pig is run. Only then is it possible to compare such things as the relative difference in pressure drop, the volume of water or condensates removed, the rate of wear on the cups or cleaning elements, etc. - but even then, it still provides only a measure of relative, rather than absolute, performance.

Invariably, when one pig "outperforms" another, a debate ensues as to why, and certain conclusions are reached. This information is passed back to the manufacturer, who incorporates it in his subsequent designs, and so the evolutionary process continues.

The problem with evolution is that it takes a very long time and it doesn't always work. Modern man may have evolved from the ape - but there are still a lot of apes around.....

Pipeline Pigging Technology

Although there is a growing awareness of the need for greater efficiency, it is probable that if intelligent pigs had not been developed, this evolutionary process would have continued. Intelligent pigs have highlighted the need for more research and development into conventional pigging.

All intelligent pigs need a clean line for optimum performance, and this requires the development of highly-effective conventional pigs and pigging programmes.

The results of an intelligent pig run often show that the pigs and/or programmes which had been routinely used, were totally inadequate. It is now accepted that regular, effective pigging, coupled with a sound inhibition programme, is much cheaper than replacing a pipeline.

But what is effective pigging? At this moment, no-one knows. There are lots of theories, but few, if any FACTS.

In most, if not all cases, pig manufacturers' recommendations for optimum performance are based on "experience". Normally, experience is perhaps the best possible way of establishing performance parameters, but in this case it should be remembered that it is not the manufacturers that have the experience - but the operators.....

A certain amount of this operational experience is fed back to the manufacturer, often in the form of complaints, but the majority is not. Indeed, many operators regard the results of a pig run as confidential, and so very little actual experience is shared. The manufacturers' recommendations therefore rely heavily on the limited amount of information which does filter back to them, together with perhaps some very modest research or observations of their own. This is clearly inadequate, and is the reason why the first step in any study must be to make a concerted effort to gather as much experiential information as possible before deciding on the R&D programmes that will be required.

In December 1990, On-Stream Systems Ltd was contracted by CALtec Ltd, a subsidiary of the BHR Group, to work with it in carrying out a detailed study of the current state-of-the-art in conventional pipeline pigging. Apart from being a valuable guide in its own right, this study will point to the areas in need of a concerted R&D programme. It may also point to the form that such research should take.

The study, which is funded by a consortium of major pipeline operators, is scheduled for completion in July, 1991.

At this time it is impossible to tell which aspects of conventional pigging will be found to be in need of a formal R&D programme, or what their order of priority might be, but it is likely to include some or all of the following:

the effects of velocity, and determination of optimum pig speeds;
design of pigs capable of performing in widely-differing diameters;

the effects of by-pass and optimum by-pass configuration;
driving cup/disc (i.e. seal) performance, materials and configuration;
the effects of the differential pressures across the seals;
the optimum type, arrangement, loading and materials for cleaning elements.

The expertise to carry out such research exists - as do most of the facilities; Fig.1 shows some of the pigging test loops currently available. What is lacking are the financial resources and, often, an appreciation of the advantages to be gained from such an R&D programme.

Further discussion of just the first two aspects listed above may provide some indication of the current situation and the advantages to be gained from a formal research and subsequent development programme.

VELOCITY EFFECT AND OPTIMUM PIG SPEED

Enough is already known about the effects of pig speed to be able to state unequivocally that it is very important.

One of the more obvious problems is that of "speed excursions". This is an area where British Gas On Line Inspection Centre has done a lot of research.

When pigging low-pressure lines, the pig will hold up at a weld bead or other obstruction until the gas pressure builds up behind it sufficiently to overcome the obstacle. It then accelerates away - often attaining speeds of well over 60mph before coming to rest once more and repeating this cycle.

This not only results in negligible pigging efficiency, but is also highly dangerous. Pigs have been known to rip open and exit a pipe on a bend when travelling under these conditions.

It is known that pipeline pressure and velocity determine whether a speed excursion will occur, but an even better understanding could help in the development of methods for speed control for use where it is impractical to create the optimum running conditions.

Perhaps the most important factor concerning speed is its effect on the sealing efficiency of a pig. The importance of creating and maintaining a good seal is obvious for the separation of dissimilar fluids (batching) in products' pipelines, for condensate removal in gas lines, for commissioning and, more recently, for providing secondary barriers for pipeline isolation.

Less obvious, but equally important, is the film thickness left behind the pig when applying *in situ* coatings or when performing batch inhibition.

Pipeline Pigging Technology

Some Available Pig Test Loops

<u>Country</u>	<u>Owner/Location</u>	<u>Dia.</u>	<u>Length</u>
Germany	Rosen Eng. - Lingen	6"	164m
"	" "	16"	-
Holland	Gasunie - Westerbork	12"	653.45m
"	" "	24"	647.42m
"	Smit-Iso - Rotterdam	4"	270m
"	" "	10"	270m
"	" "	20"	400m
Norway	Reinertsen - Trondheim	6"	-
"	" "	20"	-
"	Seanor - Loesmoen	12"	80m
UK	British Gas - Low Thornley	12"	335m
"	" "	24"	335m
"	" "	36"	335m
"	BHR - Cranfield	8"	-
"	" "	16"	-
"	ITAC - Ellesmere Port	6"	170m
"	" "	12"	170m
"	" "	20"	170m
"	Pipetex - Burnley	12"	661m
USA	GRI - Columbus, OH.	12"	700m(?)
"	" "	24"	2080m
"	TDW - Tulsa, OK.	12"	269m

Fig.1. Some available pig test loops.

Pigging research

Manufacturers of intelligent pigs have determined, and specify, the speeds at which their pigs must be run to obtain optimum performance. These range between about 1 to 10mph (0.5 to 4m/sec), although many of the geometry pigs can perform at much higher velocities.

Conventional pigs, however, must be run at the velocity at which the pipeline is operating. The speeds usually recommended for routine, conventional, on-stream pigging are 2 to 10mph (1 to 5m/sec) for liquid lines and 5 to 15mph (2 to 7m/sec) in gas lines; these figures may differ if the pig is run during construction or commissioning.

The two questions which immediately arise are firstly, is it conceivable that optimum performance can be obtained at all speeds within such a wide range? and secondly, where did these figures come from - on what are they based?

Virtually all of the published research work carried out to date appears to be in connection with the use of spheres.

Spheres have some obvious advantage from the researcher's point of view. They are perfectly symmetrical, they have only one sealing surface, and because they are inflated, their diameter can be altered. This eliminates at least some of the variables.

Some of the earliest work was carried out in 1959 by Barrett of the Shell Oil Co, Indianapolis[1], to reduce interface mixing in its 14-in, 250-mile Wood River to Chicago product line. This was soon after the introduction of what were then known as "expandable spheroids".

Although Barrett's paper is mainly concerned with reducing interface mixing and does not specifically address the effects of velocity, there are a number of aspects which are of general importance. One of these concerns the effect of the sphere/pig diameter ratio on sealing efficiency; Fig.2 is a reproduction of the graph published at the time.

Barrett's tests were carried out in a 1-mile long 13.375-in ID meter prover, using spheres made from a relatively-soft (45-50 Shore "A") neoprene. Later it was found that both neoprene and nitrile rubber had a tendency to absorb hydrocarbons and "blister" and this, together with significant improvements in their mechanical properties, has led to the almost exclusive use of polyurethanes today.

Among the many interesting facts observed during his research was the relative volumes of fluid leaking past the spheres - in both directions - with different sphere/pipeline diameter ratios. This is referred to as "flow forward" and "flow back". He states:

"Indications are that the 'flow back' across a spheroid inflated to the optimum diameter of about 1% larger than the pipe ID is in the order

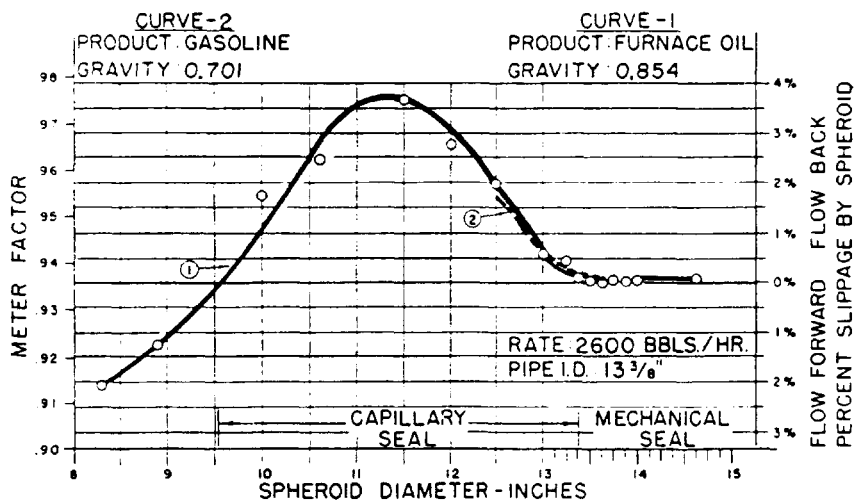


Fig.2. Slippage of product past a spheroid of varying size.

of 0.02-0.04% of the total volume displaced. Thus the 'flow back' from front to rear of a properly-sized spheroid is minimized, but it can never be eliminated".

It should be pointed out that the bore of a meter prover cannot be compared to the surface roughness of an average pipeline, and oversizing a sphere by 1% in a pipeline would simply result in unnecessary wear. It is now generally accepted that spheres should be sized to the line ID.

Spheres were first used in multi-phase pipelines in 1958[2], and at about the same time as Barrett was doing his work (1959), David W.Bean and H.Norman Eagleton of Colorado Interstate Gas Co did some studies[3] on the use of spheres for the control of liquid holdup in an 8-in multi-phase pipeline.

In 1963, Natural Gas Pipeline Co of America conducted tests using spheres to control liquid holdup on a 13-mile section of 10-in pipeline. These experiments formed the basis for a mathematical model designed to predict the performance of multi-phase pipelines, which was developed in 1964 by Alvis E.McDonald and Ovid Baker of Socony Mobil Oil Co Inc[2].

For reasons which are not apparent little, if any, further research seems to have been done for another 14 years. Then, in 1978, Hara *et al.* of Nippon Kokan KK published a paper[4] which described their experiments using spheres in a 4-in, 1300-m test line to determine the pressure drop for different products when transported through a pipeline, separated by spheres. Among

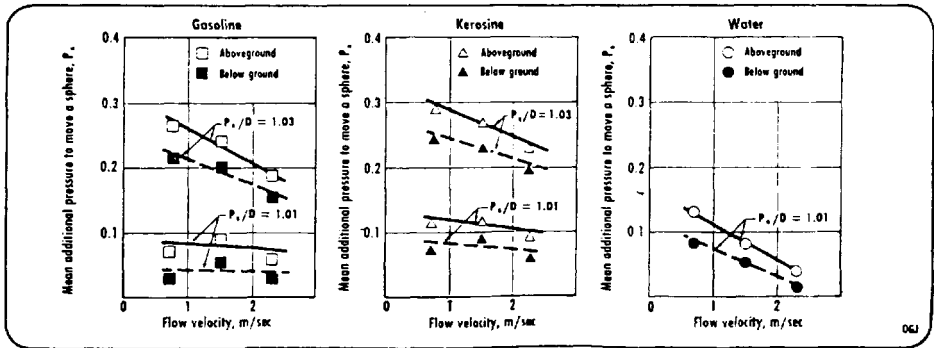


Fig.3. Flow velocity vs pressure to move a sphere.

the numerous interesting observations was: "that the actual pressure required for transporting two spheres simultaneously is 10% smaller than the sum of the pressures for transporting a single sphere".

They also noted that the 5D bends showed no increase in the differential pressure across the sphere, and "can be assumed as parts of the straight line".

Of particular interest, however, was the reduction of differential pressure across a sphere, with an increase in velocity. This is shown graphically in Fig.3, which is reproduced from their paper. Although these reductions were only of the order of 0.7psig (0.05kg/cm²), when the velocity was doubled (from 1m/sec to 2m/sec), it may well have a significant impact on the results of some further research which they carried out, details of which were published early in 1979[5].

This later work was designed to study the mixing of dissimilar fluids when separated by spheres at the interface. It produced a great deal of interesting data concerning sphere performance in general.

It confirmed that although the frictional resistance (and hence differential pressure) is nearly constant, it does decrease slightly with increasing velocity.

It was noted that flow forward and flow back was equal at a velocity of about 1.3m/sec (4.3ft/sec). At lower velocities, flow back decreased, but flow forward increased while at higher velocities, the reverse applied; the graph showing this is reproduced in Fig.4.

They made the reasonable assumption that product flows forward due to the frictional resistance of the sphere (i.e. the differential pressure) and flows back due to product viscosity.

In pigging, it is generally the flow back which needs to be minimized (e.g. for dewatering, condensate removal, etc.) so for optimum liquids' removal using a sphere, these tests indicate that speeds should probably not exceed

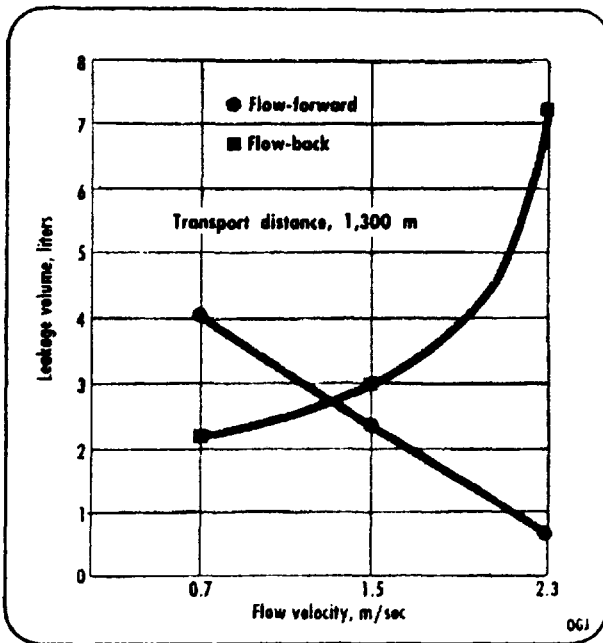


Fig.4. Leakage past a sphere.

about 1mph (0.5m/sec). However, with an increase in velocity, it has already been established that there is a very small decrease in differential pressure, and the graph shows that there is similarly a decrease in flow forward. This supports the previously-mentioned assumption, but it does beg the question as to whether, if a small increase in differential pressure could be induced when operating at velocities above this theoretical optimum, it would not only increase the flow forward, but also significantly decrease the flow back.

It must be said that in the development of a computer program called TAPTWO during 1978[6], Kohda *et al.*, also at Nippon Kokan KK, contradicted some of the previous findings. In particular, they stated that "pressure drop across a pig is independent from the pig velocity and a function of pig diameter". This statement is certainly valid for the pig diameter, and may have some validity with respect to velocity too, if the change in pressure drop is considered in relative terms. Certainly, the pressure drop with increase in velocity is very small, but it could be vitally important.

Some relatively-simple research, followed by some basic design engineering aimed at controlling the differential over a very small pressure range, may well result in the ability to tailor a pig to provide optimum (and predictable) performance for any particular pipeline, regardless of its velocity.

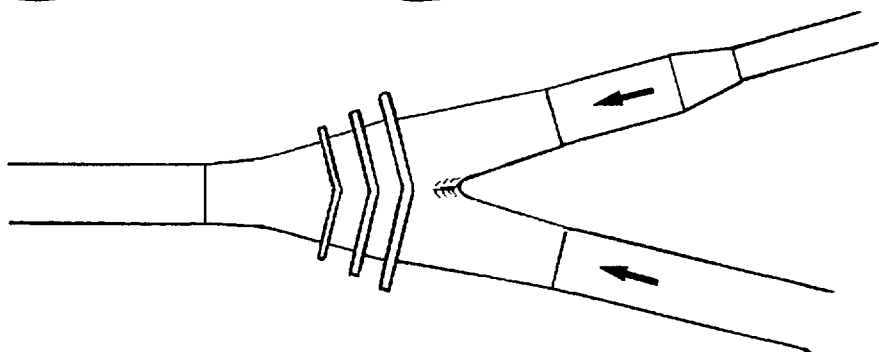
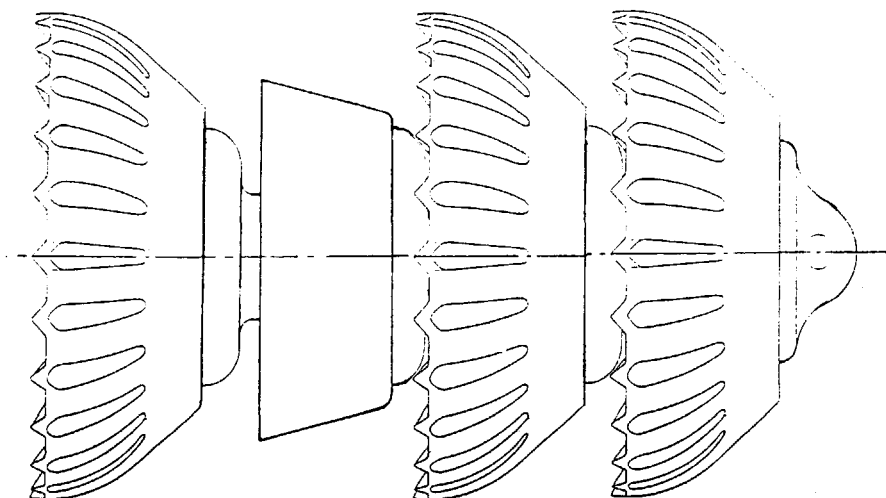
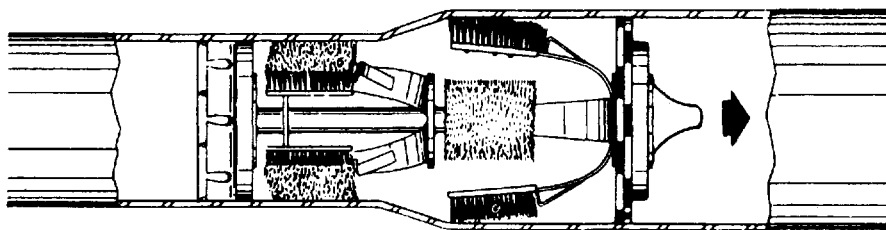


Fig.5 (top). Cut-away view of the WCK-12DD dual-diameter pig.

Fig.6 (centre). S.U.N. multi-size pig.

Fig.7 (bottom). Wye with reduced branch.

It is conceivable that research and development such as this could lead to the safe operation of multi-phase pipelines with significantly smaller liquids' handling facilities (e.g. slug catchers) and the virtual elimination of slugging - a pipeliner's "dream come true"....

PIGS FOR DIFFERING DIAMETERS

"Double-diameter" pigs are capable of traversing pipelines which have been built with more than one nominal diameter in between pig traps.

To reduce shipping costs, it was not unusual to design a pipeline with two diameters, so that the smaller pipe could be transported inside the larger one. This resulted in initial savings, but maintenance costs are generally higher and pigging is, at best, a compromise.

Most pig manufacturers have "double-diameter" pigs in their range, typical of which is the *WCK-3DD* of T.D.Williamson (Fig.5). One company in particular, S.U.N.Engineering, has done considerable work on the development of double-diameter pigs, and it now has a range which is capable of running in lines which have three, and in some cases even four, nominal pipe sizes between the large and the small diameter. A typical S.U.N. pig is shown in Fig.6.

Very few new pipelines are now laid with more than one diameter between traps. However, the increasing need to tie-in marginal fields to existing export pipelines is highlighting the importance of developing pigs which are capable of extreme double-diameter performance. Precisely how "extreme" will need to be studied carefully, but 10in or 12in into 30in (i.e. 9 or 10 pipe sizes) may well be typical.

If only liquids' removal was required, a sphere or a foam pig run through a tee may well suffice, but this would not be adequate for effective solids' removal. Most importantly, intelligent pigging would be impossible.

Effective cleaning and intelligent pigging will require an arrangement similar to that shown in Fig.7. This shows a wye installed in the export line, with a reducer upstream on one leg to enable the smaller-diameter marginal field line to be tied-in.

It is unlikely that an intelligent pig can be designed to have extreme double-diameter capability, so the challenge will be to design a conventional pig which can both clean the small-diameter line and/or tow an intelligent pig behind it.

Clearly, this will require some radical design and some extensive trials - all of which must be funded. But the rewards to the operators of marginal fields

will be tremendous. A small-diameter inspectable, piggable, pipeline which can be tied-in to an existing large-diameter export line, will indeed be a major step forward.

There is little doubt that study of the past practices and the present and future needs of pipeline operators will define other research and development programmes which will provide very significant further technical and financial rewards.

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