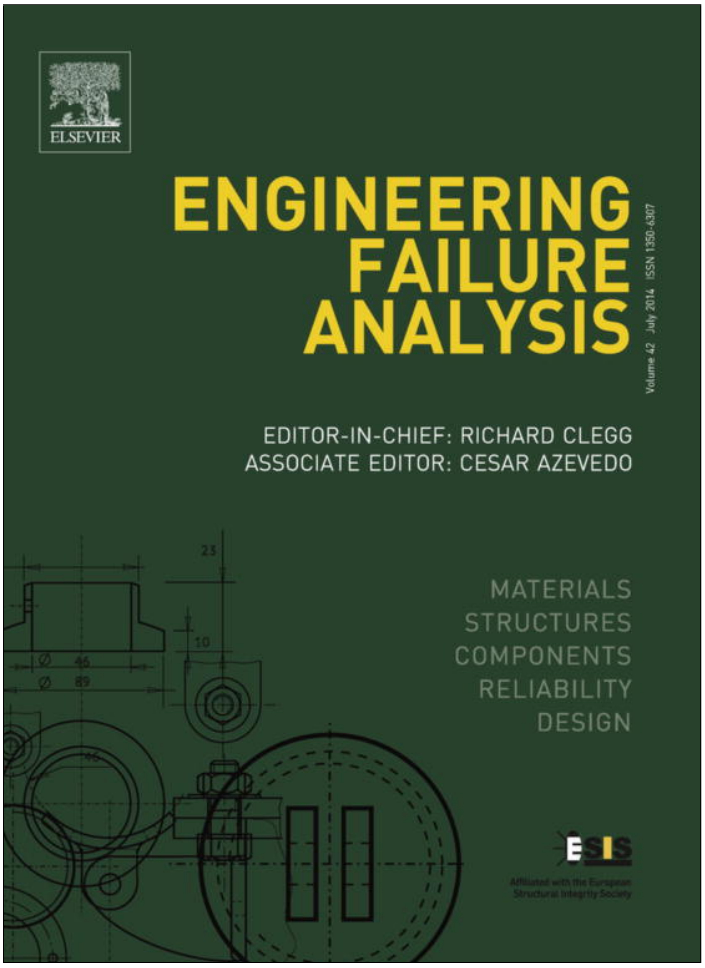
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Review

Challenges to the integrity of old pipelines buried in stable ground

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ABSTRACT

A succinct description of the particular conditions that have led to failures and damage of buried pipelines in Argentina is given in this article. The particular characteristics of soil, demographic evolution, original construction standards and procedures, and specific damage conditions based in case histories, are taken into account.

The purpose of this review is to contribute in orienting the efforts by operators and regulation bodies in order to efficiently increase the reliability of onshore buried pipelines. The author has been involved in many failure analyses involving pipelines in this country, some of the latest being related to explosions involving natural gas pipelines and related equipment.

The Argentine high-pressure oil and gas transmission pipeline system includes more than 40,000 km of buried piping. Diameters range from less than 14–36 in. Construction dates of most of these pipes range from around 1960 to around 1980. Particular cases discussed are:

- Old pipelines in stable ground
- Failures by SCC in buried pipelines
- Dealing with low-frequency ERW seam pipe
- Unknown materials and historical conditions of operation
- Integrity of old repairs
- Influence of demographic changes along right of ways

Contents

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1. Introduction

South American countries are fast exploring and exploiting their oil & gas resources. Some are relatively newcomers to the industry; and therefore, not much experience is available as to what are the most important menaces to the integrity of the facilities. This is the case, most notably, of Bolivia, and to a lesser extent, of Peru, Colombia and Ecuador. Although Venezuela has been for a long time a large exporter of crude, not that much experience has been gained in terms of integrity of large pipelines. Pipelines and related facilities in Brazil are also relatively new.

Other countries have a long history of oil & gas pipelines, mainly for local energy requirements. Argentina, for example, used to have large state-controlled oil & gas facilities. Most facilities built as early as the late 50s are still being run; and so, failures due to environment, operation and third party damage have been relatively frequent and fairly well documented.

With the exception of failures initiated because of gross overloads, internal combustion, accidents or sabotage, pipeline failures initiate from previous damage in the pipe body or in the longitudinal and circumferential (girth) welds. There are a number of causes that have been found to produce in-service degradation in buried oil and gas transmission pipelines, all related to mechanical and environmental damage. Typical environmental in-service damage types are: corrosion, fatigue, hydrogen stress cracking, and stress corrosion cracking.

Corrosion and third party damage are by far the most frequent causes for pipeline failures. Characteristics of these mechanisms are well described in the literature. In this article we will give a succinct description of the particular conditions that have led to failures and damage of buried pipelines in Argentina, taking into account the particular characteristics of soil, demographic evolution, original construction standards and procedures, and specific damage conditions based in case histories [1]. The purpose of this article is to contribute in orienting the efforts by operators and regulation bodies in order to efficiently increase the reliability of onshore buried pipelines. The author and collaborators have been involved in many of the failure analyses involving pipelines in this country, some of the latest being discussed in a recent article dealing with failure investigations of explosions involving natural gas pipelines and related equipment [2].

2. Old pipelines in stable ground, Argentina's experiences

The Argentine high-pressure oil and gas transmission pipeline system includes more than 40,000 km of buried piping. Surface coatings are mostly of the tar and glass fiber type. Longitudinal tube seams are made with both Electrical Resistance welding (ERW) and Double Submerged Arc Welding (DSAW). Diameters range from less than 14–36 in. (350–900 mm). Construction dates of most of these pipes range from around 1960 to around 1980.

Until the 1990s, Argentina had a tradition of state-controlled companies designed to develop and apply technologies to provide energy for local use. This has been the case of YPF, an oil company that at a time provided 100% of the country's crude and refined oil needs. Similarly, Gas del Estado (State Gas) was responsible for the development of the natural gas (NC) pipeline network. A large portion of the energy, such as electricity generation and heating for industrial and household use derives from natural gas. Compressed NG fueled vehicles are also very common, especially in city transport.

The use of natural gas has increased to a point when the country is nowadays importing some of its natural gas needs, mostly from fast developing Bolivian fields. The increase in energy needs has not been matched by an increase in local oil & gas production, partly due to a poorly designed dismemberment and privatization of the state owned companies, in the 1990s. This was followed by restrictions in fares and revenues for the companies (mostly European) that operate upstream and downstream systems. Accordingly, these companies severely reduced investments. In 2012 YPF was re-nationalized, after the government retook control from Repsol [3].

Most facilities built as early as the late 50s are still being run. Gas pipelines San Martin and Norte, which run from gas fields down south and up north (respectively) to the industrialized central region of the country, have each several thousand kilometers of pipelines which are more than 60 years old. Pipelines from the oil and gas fields from the west date back to the 80s. The system is continually being upgraded, but still most of the oldest pipelines do not have alternative loops in case of failures or scheduled repair, for which it is necessary to close down a tract.

Most pipelines run through flat, stable, sedimentary land, called pampa. This pampa could be either dry (south and west) or wet (midland). Failures due to environment are mostly related to corrosion; as usual, third party damage is the most frequent cause for failures [1].

Over the last 20 years, interest of integrity managers have been focused in failures and damage related to the following conditions:

- Stress Corrosion Cracking (SCC).
- Electrical Resistance Welds (ERW) and old repairs.

- Lack of materials identification.
- Lack of data on operating conditions.
- Increase in population around pre-existing pipelines.

A brief description of these issues and how these conditions are managed nowadays follows.

3. Failures by SCC in buried pipelines

Until the 1990s there had been no record of SCC as a main cause of failures in Argentine pipelines, but as the pipeline system became of a certain age this mechanism started to have an important impact on reliability. Several blowouts have been attributed to high pH SCC in different oil and natural gas transmission pipelines, which occurred by the sudden propagation of longitudinal cracks at the outer surface of the pipes [4].

Stress Corrosion Cracking (SCC) is a term used to describe service failures in engineering materials that occur by slow environmentally induced crack propagation. This phenomenon is associated with a combination of stress (applied or residual) above some threshold value, specific environment and in some systems metallurgical conditions, which lead to surface cracks with a high aspect ratio (long and shallow). SCC has been recognized as a cause of failures in high pressure gas and oil transmission lines since mid-60s. Two forms of SCC in the outer surface of buried pipelines have been identified: high-pH or "classical SCC" and low pH or "near neutral SCC" [5,6]. Both types of SCC have only been observed under disbonding coatings and it is generally accepted that a fluctuating stress component is required for crack growth.

The high-pH form is by far the most reported form of SCC, all of the more than 20 SCC – related failures or near incidents reported in Argentina respond to this mechanism. High-pH SCC in pipelines is characterized by the presence of patches or colonies of numerous fine longitudinal, usually very shallow, intergranular cracks with little evidence of secondary corrosion. Cracking is associated with relatively concentrated carbonate–bicarbonate solutions [7] having pH values of approximately 9. The growth rate of this type of SCC depends exponentially on temperature and stress level. Because of this, the number of failures falls markedly with increased distance from compressor and pump stations. Cathodic protection (CP) plays an important role in high-pH SCC because the range of electrochemical potentials for highest susceptibility is between -600 and -750 mV ($Cu/CuSO_4$), and CP is effective in achieving these potentials under disbonded coatings.

Characteristics of the failures are: colonies of intergranular and branched cracks, a considerable concentration of carbonates and bicarbonates in the soil, a black film of magnetite covering the fracture surface in the initiation sites, high pipe wall temperature and stresses, low hardness in base material, and electrochemical potential in the range of corrosion protection. Fig. 1 is an example of an SCC colony (a), cryogenic fracture (b) of the specimen gives a clear evidence of typical preexisting penny shaped cracks at the outer surface of the pipe wall.

In-service fracture usually occurs by mechanical tearing of the ligament, when the reduced remaining section of the wall could no longer support the internal pressure. The consequent fast growth of longitudinal cracks stop when the drop of

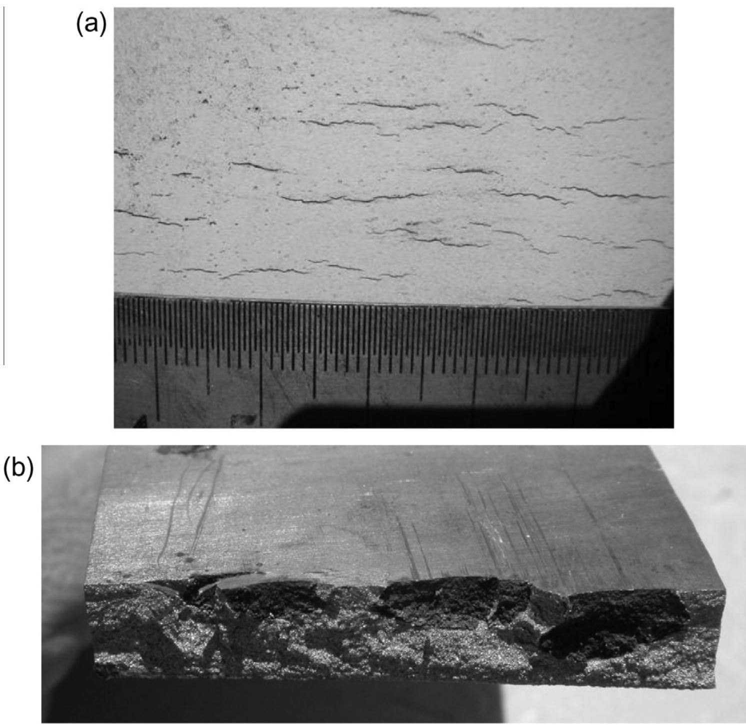

Fig. 1. SCC cracks (a) colony in outer surface and (b) after cryogenic fracture [4].

internal pressure due to leakage makes the hoop applied stress to be reduced below the necessary crack driving force. The length of the final fracture is related to the relationship between crack propagation and pressure release rates. Crack growth rate is controlled by the material fracture toughness, and pressure release rate is controlled by compressibility of the fluid. In oil pipelines, this occurs when crack lengths are of the order of a meter (Fig. 2a), while for natural gas pipelines cracks are usually 20–50 m long. Here, dynamic loads due to gas jet and sometimes gas detonation produce large deformations in the pipe, see for instance Fig. 2b. In any case, cracks usually stop a short distance from the girth welds, due to compressive residual circumferential stresses in the nearby base material.

Most common mitigation measures include the use of models that correlate all service and environment conditions in order to define areas most prone to localize SCC damage. NDT inspection is carried out either with In Line Inspection (ILI) tools or direct assessment from the outer surface, see for example Fig. 3. According to damage severity, damaged sections are repaired either by grinding and recoating, or by replacing defective tracts. Most effective vaccination measures against SCC include periodical hydrostatic testing (typically up to a hoop stress close to the yield strength of pipe base material). With this, the operator ensures on one hand that no critical defect will survive, since it will fail during the test. On the other hand, SCC cracks and any other sharp discontinuities that survive will remain immersed in a plastically deformed area that induces compressive residual stresses. This type of testing is repeated at intervals during the service life of the pipeline (typically, 5 years) and complemented with suitable, specific periodical inspections [8].

SCC failures in Argentina, however, were initially not adequately prevented with the use of models. The need for high temperatures results in most failures within the first 20 km downstream from the compressor station. But some Argentine soils have low thermal conductivity, so SCC failures have been found as far as 100 km downstream a compressor station [9]. More reliable correlations have been found with geographical data related to flat lowlands, where dry–wet conditions change yearly, resulting in the concentration of carbonates beneath disbonded coatings from periodical evaporation of ground water.

Recoating is relatively expensive but has been the solution of choice in the last years in single – pipeline systems, because it does not require flow interruption. Some problems with this solution have been recently found in old pipelines, due to low strength of girth welds that made some of them fail when the pipeline was unearthed and hanged for the recoating [10].

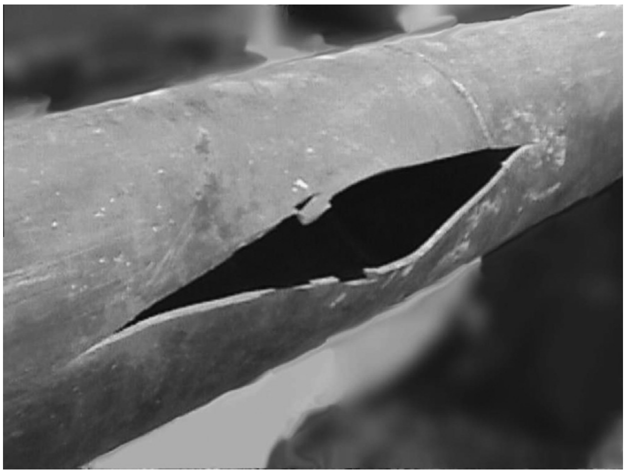

Fig. 2a. SCC failure in a 14 in. ERW oil pipeline [4].

Fig. 2b. Failure in a natural gas pipeline [4].

Fig. 3. Direct assessment of SCC in a buried gas pipeline [1].

4. Dealing with low-frequency ERW pipe

Longitudinal welds generate stress raisers, residual stresses and metallurgical changes. Transverse residual stresses are about half the yield strength of the base material. Submerged Arc Welds (DSAW) have a much better history of reliability in old pipelines, when compared with Electrical Resistance Welded (ERW) seam welds. Special integrity assessments are required to address potential seam-defect problems in low-frequency ERW pipelines in high consequence areas [11].

ERW seam-welded pipes are made by rolling a plate between clamps, pushing both edges until electric contact is made, and then heating under loading to produce the weld. These processes generate perimeter displacements that induce elastic hoop stresses in the material. After cooling of the joint a circumferential residual stress distribution is left, which is tensile in the outer surface, where cracks or other defects are usually initiated by SCC, corrosion, fatigue or other mechanisms.

The ejected material is eliminated mechanically with a cutting tool, in a process called shaving. This process leaves marks on the surfaces that work as possible crack initiation areas. Subsurface plastic deformation due to shaving also creates a very local state of residual tensile stresses in the through thickness direction. Both surface marks and subsurface residual stresses could greatly influence the conditions for SCC crack initiation.

Defects typically associated with ERW, especially to those welds carried out with earlier low frequency electric heating, are due to incomplete joining and internal defects (inclusions, lack of fusion, etc.) in the middle area of the weld. These are known to have led at least to one fatigue – related failure in an oil pipeline [12]. One typical form of defect is the so-called hook crack, in which an inclined crack is formed a couple of millimeters away from the weld center line, following the lamination planes of the base plate.

During the weld process, the heated material is ejected from the center of the thickness toward the surfaces of the pipe. Lamination defects, originally parallel to the surface, are reoriented through the thickness. This decreases the resistance of the weld to circumferential stresses. Fig. 4(a, b, X25) shows two cross sections of ERW welds. The one at the left is unbroken, after sustaining certain amount of plastic deformation. The light vertical line is the weld itself; the originally horizontal metallographic banding bends at each side of the weld. Note how the small crack at the pipe surfaces at the bottom of the photo follows a metallographic path, typical of a hook crack. The one at the right is a specimen broken at the weld area, at a stress much lower that yield strength, due to the coalescence of weld defects (lack of fusion and stitching).

Lamination defects have extensively been detected in argentine ERW oil pipelines by means of transversal magnetic flow ILI and the FAST ultrasonic technique. An experimental study showed that the largest lamination defects found in base material reduced burst pressure by less than 25%, while defects associated with the weld reduced burst strength by up to 50% [13]. These results show that the location of the defect is more important than its size, the main reason being the low toughness of the weld. Several of the lamination defects that derived in hook cracks had been characterized originally by the FAST NDT technique as inclined lamination defects. This technique requires direct access to the pipe outer surface, so expensive

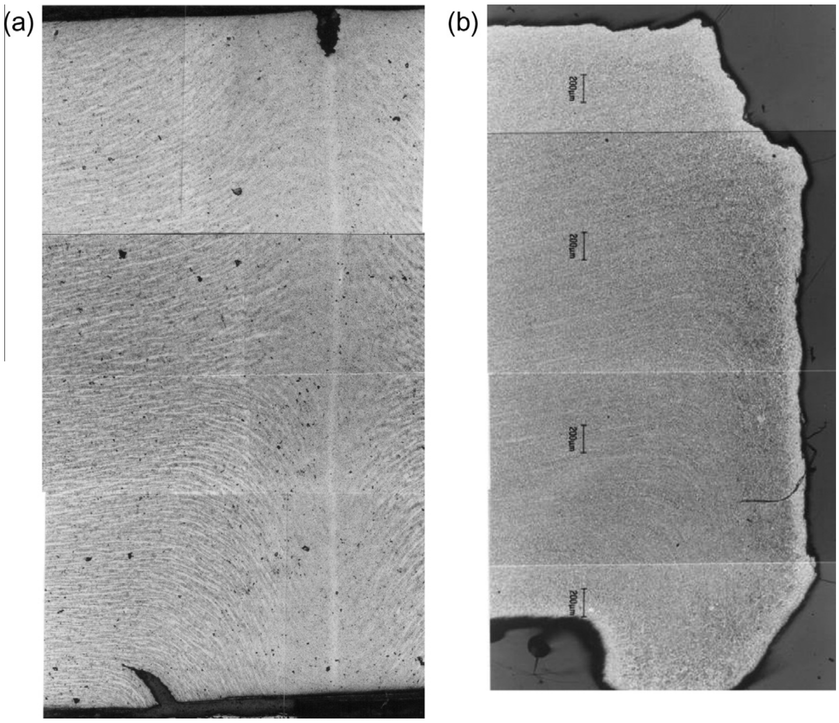

Fig. 4. (a, b, X25) two cross sections of ERW welds [12].

digging and recoating is required for every measurement. Improvements in this technique make it possible now to yield accurate information on defect morphology.

Some defects identified as curved or inclined lamination defects had in fact an associated through-thickness crack. These results confirm the importance of the position of the defect relative to the seam welds to define their criticality, and the validity of the restrictions imposed by Fitness for Service criteria, such as Section 8 of API STD 579 [14].

Given the particular metallurgical, mechanical and geometrical conditions of the welds, and their possible influence on the susceptibility to SCC, experiments were carried out for evaluating the susceptibility to SCC of ERW seams [15]. It was found that susceptibility of the ERW seam welds is much higher than for base materials, so that the welds define the length of the pipe that is susceptible to SCC. Threshold pressure estimates for SCC initiation were defined from tests at elevated temperature, service temperature, and literature correlations. Fabrication residual stresses were also measured and taken into consideration. SCC threshold pressures for these lines are controlled by the ERW welds; the pipe tracts that are considered to be susceptible to SCC are those that undergo a service pressure of at least 25 bar. This represents about 70% of the length of the pipelines studied.

5. Unknown materials and historical conditions of operation

One of the side effects of the split of state owned oil & gas companies into several private owned ones was that large amounts of information got lost in the process. Data for old systems were not well organized to begin with, and during handing over documentation was lost (sometimes probably even deliberately sabotaged). As a result, new operators did not have a reasonable understanding of previous conditions of much of their pipelines. This resulted in some early failures for the new owners that led to further research efforts.

One interesting case is that of the (probably) only documented case of a fatigue failure of a natural gas pipeline [16]. The sudden propagation of a fracture at the DSAW seam weld provoked a blowout in a 45 year old 24″ gas pipeline. Oddly enough for gas pipelines, it was found that fatigue cracks had propagated from a large embedded lack of fusion defect, Fig. 5. This fabrication defect was due to a gross lack of alignment during seam welding.

Previous in-line inspections failed to detect any geometric defect. No evidence of third party damage was found. Prompt rescuing of relevant specimens at the initiation site allowed having fracture surfaces in very good conditions, and to recover good details of the propagation history in the surfaces. This allowed obtaining notably precise crack growth rates from fatigue striation marks and ensuing fatigue life estimations.

Due to large discrepancies between preliminary fatigue life calculations and what the company considered the service history of the pipeline was, further investigations were done. Tests were carried out to characterize propagation of fatigue cracks in weld metal, at levels of cyclic stresses similar to those produced in service. Fatigue growth was modeled by integrating experimental results and by extrapolating striation spacing in the fracture surface of the failed pipe. It was found that

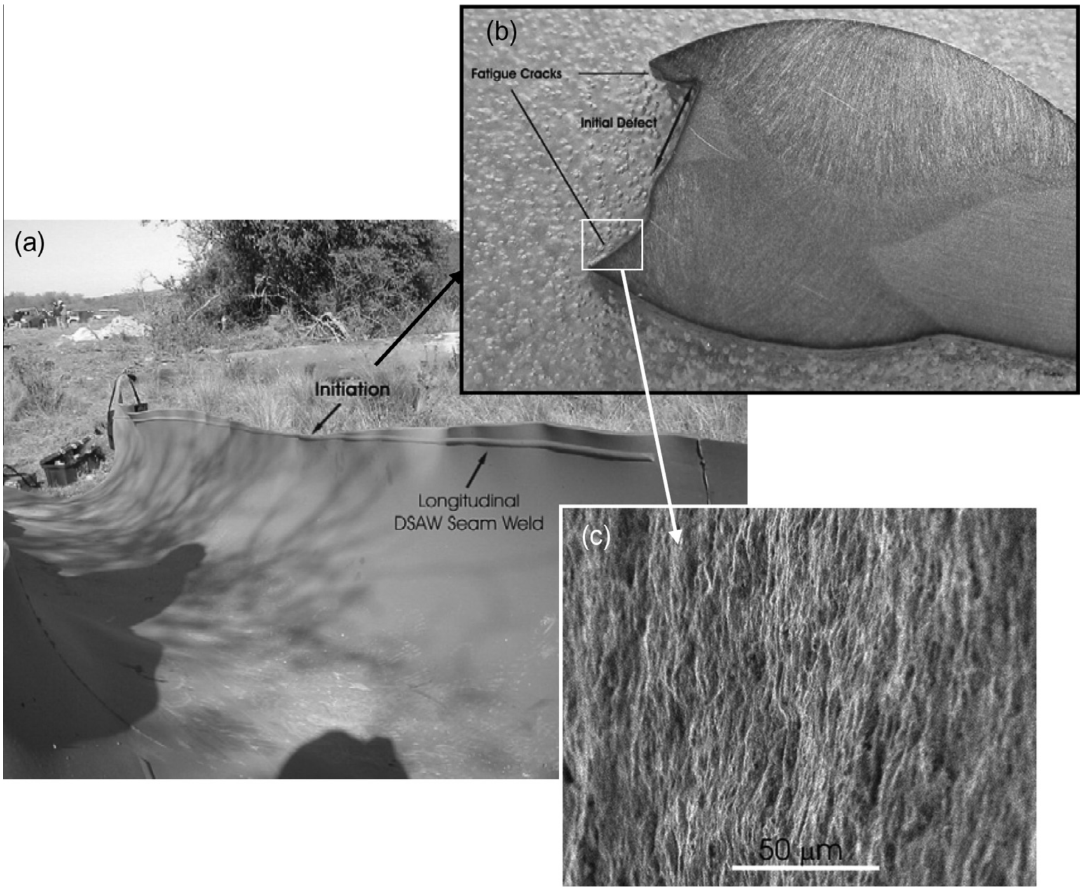

Fig. 5. (a) Blow out of gas pipeline, (b) fatigue cracks propagated from embedded weld defect and (c) striation marks at fracture surface [16].

in the early life of the line many more large pressure cycles than expected had occurred. Most reasonable hypothesis for large pressure cycles in this gas transmission pipeline are related to using the line as storage capacity (line pack) to deal with large variations in gas consumption during the day.

Another problem faced after privatizations was assuring fitness for purpose due to lack of information about pipe materials. The ABI (automated ball indentation) technique is a nondestructive test designed to determine yield strength of line pipes [17], which takes a few minutes and can be carried out, in most cases, while the equipment is operating. The test consists of a spherical tip indentation, carried out in a few cycles, while load and displacement of the tip are recorded through high precision and linearity sensors (Fig. 6). These data are then used to estimate material mechanical properties.

6. Integrity of old repairs

Old technologies were deficient not only for construction but also when repairing criteria were required. A serious blowout followed by fire occurred in 1998 in the 16″ North gas pipeline, which provoked the death of 9 employees working in repairing the pipe. The Argentine regulatory agency for natural gas led an enquiry during summer 98/99, that included the pipeline operator, Justice Representatives, and pipeline integrity specialists [18].

Two groups of deep pits were detected in the ill-fated section, separated by a 260 mm ligament, from which a ductile longitudinal crack propagated. The pits were long but narrow, axial to the pipe, with channels and parallel plateaus, typical of microbiologically induced corrosion (MIC). These pits had been detected by ILI a year before, the blowout occurred when the section was being readied for repair.

This section of pipeline had a history of MIC damage and had been already frequently subjected to repairs. The failure occurred in a zone of the pipe with tubes made of three different materials. The original material dates from the date of manufacture of the, then, oil pipeline (1978). A better material was used in a 1992 repair, with improved strength and toughness and lower anisotropy. The material in the ill-fated section had intermediate characteristics, probably dating to a previous (unrecorded) repair.

The evidence points again to poor maintenance and operation procedures. After all legal actions ended, light had been shed upon the most likely root cause for this incident. The origin of the strange shaped, long and narrow pit could be traced to a maintenance procedure. Previous repairs were undergone after ILI indications, which are referred to the position of girth welds. After exposing the pipe, location of the weld beneath the coating was sometimes made by carving the coating with a

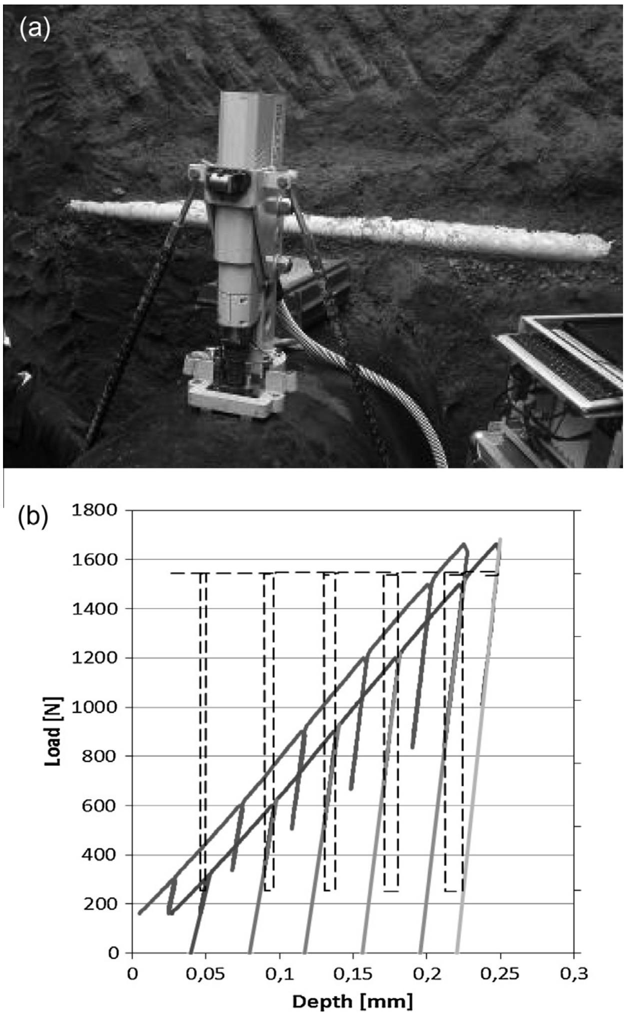

Fig. 6. (a) ABI test of a buried pipe and (b) typical load–displacement data for strength calculations [17].

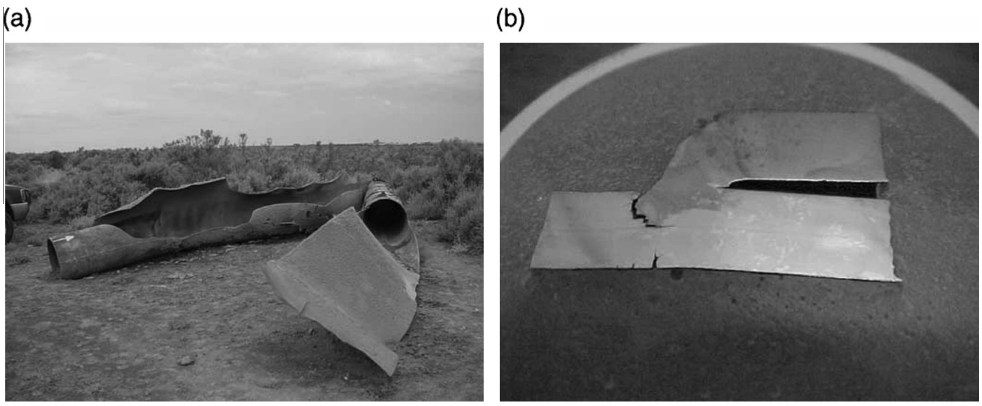

Fig. 7. (a) Burst of a 24″ gas pipeline. (b) Fracture initiation at a rectangular repair patch [19].

cutter, until detecting the weld reinforcement. Apparently, in this case the original carving was out of target; and once the repair was completed, the coating was not repaired. In a very aggressive environment, MIC developed quite quickly in the exposed notch.

A couple of failures during late 90s were related to inadequate design and installation of repair patches and fillet welds of poor quality, see for example Fig. 7 [19]. After an extensive review of ILI data, direct assessment found that fillet welded patches had been widely used in gas and oil pipelines for many years [20,21]. The most common problems associated with these failures are:

- Very poor through the thickness strength of the old pipe materials, due to severe microstructural banding.
- High impurity levels and sometimes also lamination defects from aligned non-metallic inclusions.
- High through-thickness stresses at the toes of the longitudinal patch-to-pipe fillet welds.
- Welding defects, mostly undercuts and lack of fusion.

Today pipeline operators still have to deal with many repairs of which little is known. In Line Inspection (ILI) techniques are used to detect and rank the criticality of defects and previous repairs. In assessing the reliability of an old pipeline it is necessary to evaluate whether the condition of these repair patches is critical, to define the probability of failures, and when the probability is high, to define and schedule future preventive and corrective actions.

After extensive experimental tests and numerical simulations [22], a ranking of reliability of old repair patches in an operating pipeline was defined. Patches with higher risk to integrity are those that have the following:

1. They were placed with the pipeline at a pressure less than half of MAOP (maximum allowable operating pressure).
2. They were placed to repair a defect of large dimensions and deeper than around 40% of pipe thickness.
3. They are rectangular, roughly two times longer than wide.
4. The quality of the welds is poor or doubtful, for example, no procedures or NDT records are available.

The information from the ILI tool does not allow an evaluation of the quality of the weld used in the repair, nor does it establish the pressure at which the repair was made. In general ILI information does not allow definition of the actual size of the defect that motivated the collocation of the patch. Therefore, relying on the data reported by the ILI, only the third of the four criticality above-mentioned conditions is possible to be assessed.

Normally the pipeline operator cannot proceed to the immediate replacement of all the patches detected in a pipeline. Therefore, a priority criterion is established. Table 1 shows a summary of the factors that affect the reliability of the patches welded to a gas pipeline. If reliable data for every condition can be obtained, the sum of every row in the table would allow definition of a risk index for each patch, from a minimum of 0 to a maximum of 5.

Although not completely eliminated, failures due to incorrect repairs have been markedly reduced. The mechanical interactions between pipe and repair materials are now better known, and new methodologies are continuously been introduced to ensure reliability of the repairs. Modern repair procedures rely on good control of welding variables, and on avoiding the creation of longitudinal discontinuities in the pipe surface. When replacing the failed tract is not possible, this is obtained by using full encirclement sleeve reinforcements rather than patches [23]. However, early sleeve repairs have also failed during service, due to poor manufacturing standards [24]. The main reasons for these failures have been:

- The material used to build the sleeves was old and had poor transverse strength.
- A high heat input, single pass weld procedure using a high hydrogen, cellulosic electrode was used to weld the joints.
- Loss of mechanical properties caused by hydrogen embrittlement and other defects in both weld and HAZ (heat affected zone) metal.
- Relatively high circumferential stresses were introduced into the sleeve assembly.
- Lack of fusion and other weld defects were introduced by poor weld standards.

Other risks related to sleeve repairs are weld burn-through during repair, and, on the other end of the timeline, the eventual collapse of the pipe wall under the sleeve. Local collapse of the pipe wall under full encirclement sleeve reinforcements is associated with breaks and blow outs in nearby sections of a gas pipeline, that cause large gas losses and abrupt depressurization in the repaired tract. Two examples are shown in Fig. 8.

Although these defects do not represent an imminent risk of failure, they should be eliminated because they impede the normal running of an ILI tool. Four failed repairs were experimentally evaluated, and the effects of different geometric factors were numerically assessed. All possible causes of the appearance of these defects and measures to minimize their occurrence were evaluated. The position of the repaired portion with respect to the blow out, the local geometry of the repair and previous defects, and the amount of gas caught in the interstice between the pipe and the reinforcement, all affect the likelihood of a pipe collapse under a sleeve repair [25].

Table 1
Linear summation of criticality factors for old repair patches (criticality: A + B + C).

Patch geometry	A Installation pressure		B Size of patch or repaired defect		C Qualified procedure	
	High	Low	Small	Large	Yes	No
Round or elliptical (longer along perimeter)	0	1	0	1	0	1
Rectangular, wide and short	1	1.5	0	1	0	1
square or elliptical lengthwise	1	2	0	1	0	1
Rectangular, long and narrow	2	3	0	1	0	1

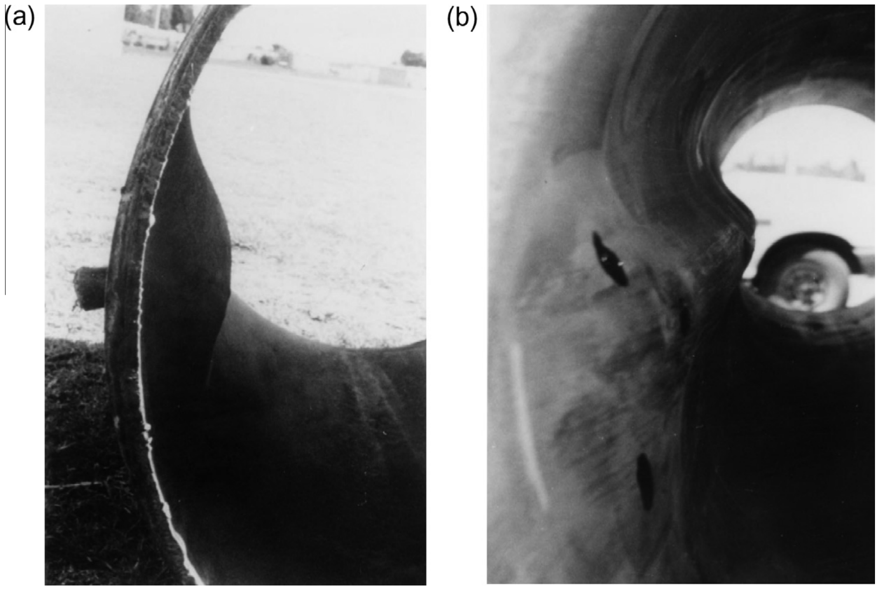

Fig. 8. Two examples of local collapse of gas pipelines under sleeve repairs [23].

Fig. 9. A tract of pipe with multiple sleeve repairs being prepared for hydrostatic burst testing [28].

In order to minimize the recurrence of these types of failure, a series of changes were introduced in the repair method, including improvements in the fabrication of the sleeves and their in-field installation into the pipeline, and NDE specifications. Determinations of minimum weldable wall thickness were improved, in order to ensure avoidance of tube perforation during welding [26]. Epoxy hardenable interstitial fillers were tested and included in the repair procedures, in order to reduce the pipe to sleeve gap and thus minimize the risk of sleeve failures and plastic collapse of the pipe [27].

Argentine oil and gas operators are still coping with tracts of densely repaired pipelines, some of which are jokingly called patch-lines. Although the integrity of each repair is well documented, a final concern came about the structural integrity of gas pipelines with multiple full-encirclement weld repairs. Work was done to identify and quantify the effects of the number and type of repairs, the distance between them, and the pressurization of the pipe-to-sleeve gap on the mechanical behavior of the pipeline. The studies included full-scale experimental burst testing and finite element modeling, Fig. 9. It was concluded that the reliability of the repairs is strongly influenced by the construction procedures, but that interaction between neighboring repairs is not appreciable if the repairs are more than a half pipe diameter apart [28,29].

7. Influence of demographic changes along right of ways

Some of the main gas distribution pipelines in Argentina are more than 50 years old. Integrity issues of these aged pipelines are related not only to material problems such as low toughness and in service damage, but also to the way demographic expansion has affected conditions in some metropolitan areas, most notably around the city of Buenos Aires. The (usually uncontrolled) increase in dwelling around (and sometimes along) the right of way has influenced integrity requirements for operators of gas pipelines in various ways:

1. Reduced acceptable risk of blow outs and other failures: this is a serious burden for integrity teams, especially in suburban areas where most of the pipelines are not piggable.
2. Increased consequences of failures in gas treating and compression plants, due to increased production requirements and space constraints.
3. Increased risk of third party damage: notably, the rate of failures due to improper use of suburban soil and tampering has not been as high as in other parts of the world [30].
4. Changes in soil conditions.

Change in soil conditions as a threat to pipeline integrity has come out as a rather unexpected issue. Experiences in the last 5–10 years by several pipeline operators revealed that soil movements and load transfer from soil to pipeline play an important role in pipeline integrity. Buried pipelines are structures that interact with the soil that is founding them. When implanted in unstable areas, pipelines are known to be subjected to additional loads transmitted by the movement of the ground. A couple of soil-related failures in suburban Buenos Aires, however, developed in very stable soils.

The reasons for the buildup of axial deformations and stresses in these gas pipelines are now understood as a consequence of the history of urban development, including three main aspects:

1. Surface loads and soil movement.
2. Changes in soil humidity.
3. Cyclic temperature changes around the pipeline.

The first aspect is obvious, the other two require some explanation. The pipelines were originally buried in areas with no urban settlements. During the years, first nearby (mostly low-income) dwellers created an almost negligible interference with the original soil conditions. Fresh water was taken from wells, and disposed of in septic chambers, so that the overall water content of the soil was maintained constant. Eventually, these settlements were connected to a central water system, and at a different time (sometimes after many years) they were connected to a sewage system. There were large intervals in which water was poured into the ground, increasing humidity.

It is well known that water saturation changes dramatically the mechanical properties of the soil: dry soil is orders of magnitude stronger than moist soil. This became a problem when coupled to the third condition: when local population started using gas from these interconnection and distribution lines, for cooking but mostly for heating, gas flow started to fluctuate with usage in an annual cycle. NG flow cycles induced marked temperature cycles in the pipeline and surrounding soil, thereby generating relatively large thermal strain gradients. These cyclic axial strains in the pipeline, coupled with the aforementioned cycles in shear strength of the soil, were probably creating small axial pull–push cycles. The cumulative effect of these cycles eventually led to high axial stresses in certain zones of the pipelines.

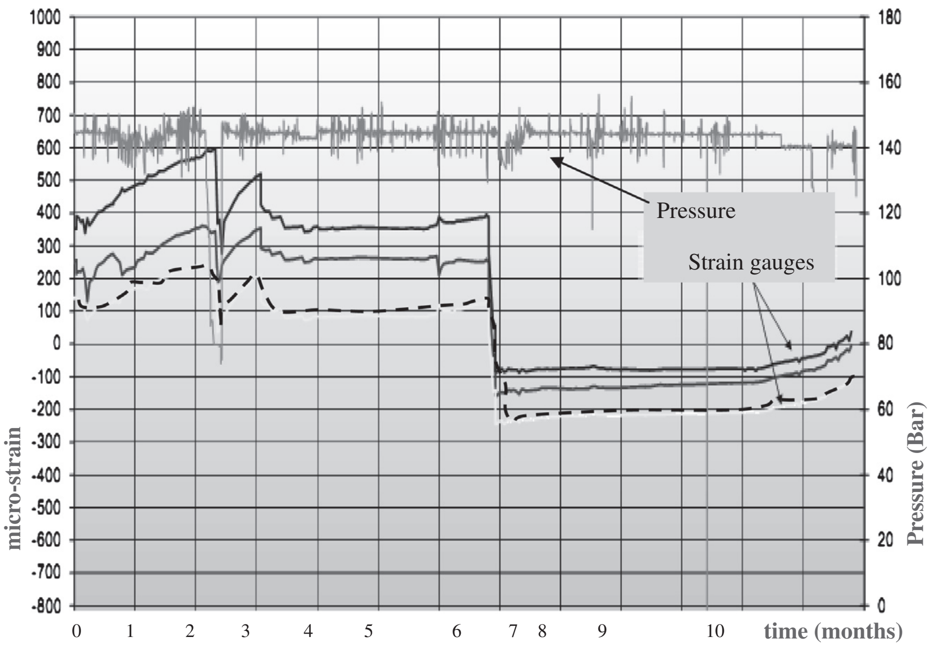

Fig. 10. Record of strain gauge readings in a buried pipeline.

Ensuring integrity of these suburban pipelines depends, in part, upon correct quantification of soil-induced pipe loads [31]. In zones of known soil instabilities, vibrating wire strain gauges placed on the pipe wall are now being used to assess the axial and bending loads transmitted to the pipe. Limit values are set as alarm levels to indicate when to carry out remedial work and/or stress relief. Fig. 10 shows a typical record of measured strains. Although a thorough interpretation is beyond the scope of this work, in this example it is seen that strains measured by the three gauges increase or decrease simultaneously, indicating tension rather than bending. Strain variations are not related to pressure variations, the abrupt decrease corresponds to work done in the right of way to relieve stresses in the pipe. Note that after this operation the pipe seems compressed, in fact this indicates that the gauges were not zeroed when placed. The slow increase at the right part of the graph indicates that after the mitigation effort the soil movement is again tensioning the pipeline.

There is a limitation to this approach when it is applied to existing facilities already in service for some time. The stress condition of the pipeline when the gauges are placed is usually unknown, so that the measurements have an error equal to the original stress state. There are at least two ways to alleviate this difficulty: one is the use of inertial ILI tools that allow comparing the present geometry of the pipeline with a previous "as built" condition. Lateral displacements and changes in curvatures can be introduced in a model, and used to assess stresses developed in the pipeline since the time of burying it in the ground. Another, more direct way, is to use a measurement technique for residual stresses, such as the "blind hole" method.

The requirements of logistics, personnel and machinery are very important in places of difficult access, so the cost of stress measurement and other direct assessments in pipelines is high. For this reason, the proper placement of sensors and appropriate monitoring of deformations is, undoubtedly, an important variable to decide an intervention for stress relief. To this purpose a very useful tool is a thorough soil–pipe computer simulation [32].

8. Concluding remarks

As in all countries, the most frequent threats for the integrity of onshore buried pipelines in Argentina are corrosion and third party damage. To contribute in orienting the efforts by operators and regulation bodies in order to efficiently increase the reliability of old pipelines, the author reviews the particular characteristics of the other most relevant damage mechanisms. These mechanisms pertain to pipelines buried in stable ground: low pH SCC, low-frequency ERW seam pipes, loss of data about material and operation, old repairs, and demographic changes along right of ways.

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